Laredo Petroleum Holdings, Inc.
Form 10-K
March 12, 2013

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, 2012
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 Holdings, 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 o	Accelerated filer ý	Non-accelerated filer o (Do not check if a	Smaller reporting company o

smaller reporting company)

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 $479.8 million on June 30, 2012, based on $20.80 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 March 8, 2013: 129,379,195

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2013 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2012, are incorporated by reference into Part III of this report for the year ended December 31, 2012.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following terms are used throughout 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.

"DD&A"—Depreciation, depletion, amortization and accretion.

"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.

"HBP"—Held by production.

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

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

"Initial Production"—The measurement of production from an oil or gas well when first brought on stream. Often stated in terms of production during the first thirty days.

"Liquids"—Describes oil, condensate and natural gas liquids.

"MBbl"—One thousand barrels of crude oil, condensate or natural gas liquids.

"MBOE"—One thousand BOE.

"MBOE/D"—MBOE per day.
"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.
"Residue natural gas"—Natural gas remaining after natural gas liquids extraction.
"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.
"Unit"—The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.
"Wellbore"—The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.
"Wellhead natural gas"—Natural gas produced at or near the well.

"Working interest"—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 on Form 10-K 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 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 ongoing 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 crude oil and natural gas;
- 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;
- discovery, estimation, development and replacement of oil and natural gas reserves, including our expectations that estimates of our proved reserves will increase;
- competition in the oil and natural gas industry;
- 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;
- the availability of sufficient pipeline and transportation facilities and gathering and processing capacity;
- uncertainties about the estimates of our oil and natural gas reserves;
- changes in the regulatory environment and changes in international, legal, political, administrative or economic conditions;
- successful results from our identified drilling locations;
- 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;
- our ability to comply with federal, state and local regulatory requirements;
- 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 on Form 10-K 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 on Form 10-K. 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

In this Annual Report on Form 10-K, 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 Petroleum Holdings, Inc., a Delaware corporation, 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 on Form 10-K for more information.

Item 1. Business

Overview

Laredo Petroleum Holdings, Inc. (together with its consolidated subsidiaries, "Laredo," "we," "us," "our" or "Company") is an independent energy company focused on the exploration, development and acquisition of oil and natural gas primarily in the Permian and Mid-Continent regions of the United States. The oil and liquids-rich Permian Basin in West Texas and the liquids-rich Anadarko Granite Wash in the Texas Panhandle and Western Oklahoma are characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of December 31, 2012, we had assembled 203,549 net acres in the Permian Basin and 37,322 net acres in the Anadarko Granite Wash and had proved reserves, presented on a two-stream basis, of 188,632 MBOE.

Our primary exploration and production fairway in the Permian Basin is centered on the eastern side of the basin approximately 35 miles east of Midland, Texas and extends approximately 20 miles wide (east/west) and approximately 85 miles long (north/south) in Glasscock, Howard, Reagan and Sterling counties, and is referred to in this Annual Report on Form 10-K as the "Permian-Garden City" area. As of December 31, 2012, we held approximately 145,800 net acres in more than 300 sections in the Permian-Garden City area, with an average working interest of approximately 92% in all producing wells.

Subsequent to December 31, 2012, we announced we are exploring options to potentially divest certain assets located outside the Permian Basin. These assets consist of our Anadarko Granite Wash properties (approximately 11% of our estimated net proved reserves as of year-end), as well as properties owned in the Central Texas Panhandle (Hansford, Hutchinson, Ochiltree and Roberts counties in Texas) and the Eastern Anadarko Basin (Caddo, Grady and Comanche counties in Oklahoma) (collectively, approximately 4% of our estimated net proved reserves at such time). There can be no assurance that the divestiture of any assets will be completed.

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, 2012, we have drilled and completed 60 horizontal wells in these four target zones, and more than 725 vertical wells in the Wolfberry interval. We have completed 34 horizontal Cline wells, 23 horizontal Upper Wolfcamp wells, two horizontal Middle Wolfcamp wells and one horizontal Lower Wolfcamp well. Our recent horizontal activity has moved toward drilling longer laterals (typically approximately 7,000 to 7,500 feet) and increased frac density (typically 25 to 28 stages) as we continue the optimization of our completion techniques. Because we drilled a mixture of long (characterized as greater than 6,000 feet) and short laterals in our 2012 horizontal drilling programs and tested various distances between frac stages, we normalized the reporting of production results for these wells by analyzing the production per frac stage presented on a two-stream basis. The average daily rate per stage for the peak 30-day production period for the 20 horizontal Upper Wolfcamp wells that were drilled and completed in 2012 was 28 BOE/D per frac stage. The average daily rate per stage for the peak 30-day production period for the 12 horizontal Cline wells that were drilled and completed in 2012, was 29 BOE/D per frac stage. The same measurement of peak 30-day production for the two Middle Wolfcamp horizontal wells averaged 34 BOE/D per frac stage and the one Lower Wolfcamp horizontal well averaged 27 BOE/D per frac stage.

We believe we have proved the commercial production viability in all four horizontal zones as of December 31, 2012, including the economic horizontal development potential of the Cline and Upper Wolfcamp shales on approximately

70,000 net acres and 60,000 net acres, respectively, of our Permian-Garden City acreage, as well as our entire acreage position for deep vertical development. We further believe that additional drilling results through February 28, 2013, coupled with our technical data and well performance, have enabled us to confirm the development potential of additional acreage in all four zones. As a result, we believe we have confirmed the horizontal development potential for the equivalent of 360,000 net acres in the four zones which 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 as of February 28, 2013.
Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage, as reflected in our 2013 capital drilling budget allocation. As a result, we expect our Permian-Garden City acreage will be the primary driver of our reserves, production and cash flow growth for the foreseeable future.
Our Anadarko Granite Wash play extends within a large area in the western part of the Anadarko Basin in Hemphill County, Texas and Roger Mills County, Oklahoma. Currently, we are drilling horizontal opportunities targeting the liquids-rich natural gas of the Granite Wash formation. The Granite Wash is a conventional play requiring geologic and engineering expertise and precise drilling techniques to ensure maximum production per well.
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, many of whom have worked together for a decade or more. Prior to founding Laredo, Mr. Foutch and members of our management team successfully formed, built and sold three private oil and natural gas companies, all of which were focused on the same general areas of the Permian and Mid-Continent regions in which Laredo currently operates. All of these companies executed the same fundamental business strategy employed by Laredo in the same general operating areas and created significant economic growth in reserves, production and cash flow.
In December 2011, we completed a Corporate Reorganization and IPO. 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 188,632 MBOE as of December 31, 2012, of which 43% were classified as proved developed reserves, and 52% 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 on Form 10-K, 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, 2012, and average daily production presented on a two-stream basis for the year ended December 31, 2012. Based on estimates in the report prepared by Ryder Scott, we operate wells that represent approximately 95% of the value of our proved developed oil and natural gas reserves as of December 31, 2012.

	At December 31, 2012 Estimated net proved reserves(1)(2)						Producing wells		Year ended December 31, 2012 average daily production(3) (BOE/D)
	MBOE	% of total reserves		% Oil		Net acreage	Gross	Net	
Permian	160,028	85	%	60	%	203,549	869	799	20,618
Anadarko Granite Wash	20,172	11	%	6	%	37,322	191	142	7,875
Other Areas(4)	8,416	4	%	4	%	67,223	349	176	2,341
New Ventures(5)	16	—	%	100	%	113,343	2	2	40
Total	188,632	100	%	52	%	421,437	1,411	1,119	30,874

(1) Our estimated net proved reserves were prepared by Ryder Scott, and presented on a two-stream basis as of December 31, 2012 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 $91.21 per Bbl for oil and $2.63 per MMBtu for natural gas for the 12 months ended December 31, 2012.
(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, 2012 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 prices were $5.97 per Mcf in the Permian area and $3.21 per Mcf in the Anadarko Granite Wash area.

(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) Includes our acreage in the gas prone Eastern Anadarko (22,602 net acres) and Central Texas Panhandle (44,621 net acres).

(5) Estimated net proved reserves of 16 MBOE are in 88,728 net acres in the Dalhart Basin, which is an exploration effort targeting liquids-rich formations that are less than 7,000 feet in depth and 24,615 net acres in other New Ventures. See "—New ventures."

Our net average daily production for the year ended December 31, 2012 was 30,874 BOE/D, 42% of which was oil and 58% 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.

In 2012, we increased our horizontal drilling activities in both the Permian Basin and the Anadarko Granite Wash. As of December 31, 2012, we had completed 60 gross horizontal Wolfcamp and Cline shale wells in the Permian and 25 gross horizontal Granite Wash wells. The Permian Basin horizontal drilling program comprises an extensive, multi-year, multiple-zone inventory of exploratory and development opportunities.

Approximately 89% of our planned drilling capital for 2013 is budgeted to be invested in the Permian Basin. We anticipate that we will continue to drill deep vertical wells for purposes of further delineating our Permian Basin acreage and holding all desired zones on such acreage. 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.

We maintain a financial profile that provides operational flexibility. At December 31, 2012, we had approximately $660 million available for borrowings on our senior secured credit facility and total debt of approximately $1.2 billion, of which $165 million was outstanding under our senior secured credit facility. Our total debt, less available cash on the balance sheet, was approximately 2.6 times our Adjusted EBITDA (a non-GAAP financial measure, see "Selected Historical Financial Data—Non-GAAP financial measures and reconciliations") for the year ended December 31, 2012. 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 derivative financial instruments 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.

At December 31, 2012, we had a total of 14 operated drilling rigs working. Ten of those rigs were working on our properties in the Permian-Garden City area, consisting of six rigs drilling vertical wells and four rigs drilling horizontal wells. Three rigs were working on our properties in the Anadarko Granite Wash, all drilling horizontal wells. Additionally, one rig was drilling an exploratory well in our Permian-China Grove area, which is described below.

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. Our drilling programs are focused primarily on oil opportunities in the Permian Basin.

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 and in the Anadarko Basin approximately 50 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 vertical 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 expect to begin its implementation in 2013 commencing with pilot programs.

Capitalizing on our extensive technical database developed in the Permian-Garden City area, we are currently testing a Cline shale exploratory concept on our Permian-China Grove acreage, located primarily in Mitchell county in Texas, which is referred to in this Annual Report on Form 10-K as the "Permian-China Grove" area.

In the Anadarko Basin, the Granite Wash horizontal potential locations have been identified through a series of detailed maps which we have internally generated based on an extensive geological and engineering database. Information incorporated into this process includes our own proprietary information as well as industry data available in the public domain. Specifically, open-hole logging data, production statistics from operated and non-operated wells and petrophysical data describing the reservoir rock as derived from cores we recovered during our drilling operations have been captured and worked.

In both the Permian and Anadarko drilling programs, the timing of drilling the 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. Our business continues to be conducted through Laredo Petroleum, Inc., a wholly-owned subsidiary of Laredo Petroleum Holdings, Inc., and through Laredo Petroleum Inc.'s subsidiaries. As of December 31, 2012, Warburg Pincus owned approximately 68% of our common stock. The Corporate Reorganization and IPO are discussed in Note A in our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

Laredo Petroleum, Inc. is also 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 and our $500 million 7 3/8% senior unsecured notes due 2022 issued in April 2012 (the "2022 senior unsecured notes"). We refer to the 2019 senior unsecured notes and the 2022 senior unsecured notes collectively as the "senior unsecured notes." Laredo Petroleum Holdings, Inc. and all of its subsidiaries (other than Laredo Petroleum, Inc.) are guarantors of the obligations under our senior secured credit facility and senior unsecured notes.

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.

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, 2012, we had approximately 145,800 net acres in the Permian-Garden City area and had de-risked approximately 60,000 net acres for horizontal Upper Wolfcamp drilling and approximately 70,000 net acres for horizontal Cline drilling. We are continuing to de-risk the remaining acreage for these zones as well as the entire acreage position for additional horizontal Middle and Lower Wolfcamp development. We are leveraging the knowledge and data we have accumulated in this area and have begun to apply it to our Permian-China Grove acreage, targeting the Cline shale, which we believe is similar to that in our Permian-Garden City area. We believe the opportunities afforded in both of our Permian areas as well as the Anadarko Granite Wash will support consistent, predictable, annual growth in reserves, production and cash flow.

Implement a development plan for our Permian-Garden City acreage. We expect our Permian-Garden City acreage will be the primary driver of our reserves, production and cash flow growth for the foreseeable future. As a result of our technical data and the performance of our 34 horizontal Cline wells and 23 horizontal Upper Wolfcamp wells, we believe we had confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 70,000 net acres and 60,000 net acres, respectively, of our Permian-Garden City acreage as of the end of 2012. Based on additional drilling results through February 28, 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 and the equivalent of 360,000 net acres for horizontal development. We further believe this de-risked acreage position (as described below) provides a multi-year development inventory to support consistent growth of reserves and production. We are creating an implementation plan to systematically and efficiently develop this acreage position as a resource play. This plan also provides flexibility to include development of additional acreage for both the Upper Wolfcamp and Cline, as well as development of the Middle and Lower Wolfcamp zones as we continue to further de-risk these zones and our remaining Permian-Garden City acreage. Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage position, as reflected in our 2013 capital budget allocation.

Capitalize on technical expertise and database. We are leveraging our operating and technical expertise to further delineate our core acreage positions. 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 60 completed horizontal wells in all three Wolfcamp zones and the Cline shale in the Permian-Garden City area, we believe we have de-risked a significant portion of such acreage. We are further capitalizing on this data and expertise through our acreage acquisition and activities in our Permian-China Grove area.

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 are refining a development plan for a portion of our Permian-Garden City area in order to minimize costs and maximize recoveries. We expect to begin implementing this plan in 2013 commencing with pilot programs to test optimal spacing of the laterals, both vertically and horizontally, in the four initial zones targeted for horizontal development. In 2012, we began and are now continuing to drill longer laterals with increased density of frac stages 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 deep vertical drilling program to continue 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. Operational control 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 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, owning and operating our natural gas gathering systems with 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, 2012, we have completed more than 725 gross vertical and 60 gross horizontal wells with a success rate of approximately 99%. Sixty of our gross horizontal wells have been drilled and completed in our current four targeted zones. Based on this drilling success, coupled with our technical data, we believe we have confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 70,000 and 60,000 net acres, respectively, of our Permian-Garden City acreage, as well as our entire acreage position for deep vertical development as of December 31, 2012. Based on additional drilling results through February 28, 2013, coupled with our technical data and well performance, we believe we have confirmed the development potential of additional acreage in all four zones. As a result, we believe we have confirmed the horizontal development potential of the equivalent of 360,000 net acres in 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 as of February 28, 2013. We believe our Anadarko Granite Wash acreage has also been significantly de-risked through our focus on data-rich, mature producing basins with well studied geology, past drilling activity, engineering practices and concentrated operations, combined with our use of new technologies. 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 exploration and development programs. We have a large library of data that is applicable to our Permian-Garden City acreage base that includes approximately 800 square miles of proprietary/licensed 3D seismic data, 130 proprietary petrophysical logs and more than 13,500 historical open-hole logs. On our Permian-Garden City acreage, we have 11 whole cores and more than 300 sidewall cores in our four horizontal target zones. We have correlated this data across our Permian-Garden City acreage with more than 725 gross vertical and 60 gross horizontal wells. Our management team has extensive industry experience. Each of Mr. Foutch's previous companies focused on the same general areas of the Permian and Anadarko Basins in which Laredo currently operates. Most members of our senior management team have more than twenty years of experience and knowledge directly associated with our current primary operating areas. As of December 31, 2012, approximately 45% of our full-time staff are experienced technical employees, including 28 engineers, 18 geoscientists, 19 landmen and 56 technical support staff.

Significant operational control. We operate wells that represent approximately 95% of the value of our proved developed reserves as of December 31, 2012, 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 Gas Services, LLC, had more than 360 miles of pipeline in our natural gas gathering systems in the Permian and Anadarko Basins as of December 31, 2012. These systems and flow lines provide greater operational efficiency and lower differentials for our natural gas production in our liquids-rich Permian and Anadarko Granite Wash plays 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 interconnecting pipelines, potentially minimizing the risks of both shut-ins awaiting pipeline connection and curtailment by downstream pipelines. We continue to expand this concept in the Permian-Garden City area by building out our crude oil transportation infrastructure in order to attempt to minimize the risks of shut-in or curtailment. We have constructed a crude oil truck station in Glasscock County, Texas, are building a second truck station and have completed the design work for a crude oil gathering system in Reagan County, Texas.

Financial strength and flexibility. We maintain a financial profile that provides operational flexibility. At December 31, 2012, we had approximately $660 million available for borrowings on our senior secured credit facility and total debt of approximately $1.2 billion, of which $165 million was outstanding on our senior secured credit facility. Our total debt, less available cash on the balance sheet, was approximately 2.6 times our Adjusted EBITDA (a non-GAAP financial measure, see "Selected Historical Financial Data—Non-GAAP financial measures and reconciliations") for the year ended December 31, 2012. We believe that our operating cash flow and the aforementioned liquidity sources provide us with the ability to implement our planned exploration and development activities and accelerate our capital program, if deemed appropriate. We use derivative financial instruments 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.

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

We focus on developing a balanced inventory of quality drilling opportunities that provide us with the operational flexibility to economically develop and produce oil and natural gas reserves from conventional and unconventional formations. Our properties are currently located in the prolific Permian and Mid-Continent regions 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 higher oil content, to be the primary driver of our reserves, production and cash flow growth for the foreseeable future and as discussed above, we are exploring opportunities to divest our non-Permian Basin assets.

Permian Basin

The oil and liquids-rich Permian Basin, located in West Texas and Southeastern New Mexico, where we have assembled 203,549 net acres as of December 31, 2012, is one of the most prolific 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 approximately 35 miles east of Midland, Texas and extends approximately 20 miles wide (east/west) and approximately 85 miles long (north/south) in Howard, Glasscock, Reagan and Sterling counties. As of December 31, 2012, we held approximately 145,800 net acres in more than 300 sections in the Permian-Garden City area with an average working interest of approximately 92% in all producing wells. In addition, as of December 31, 2012, we held approximately 57,750 net acres in the Permian-China Grove area, primarily in Mitchell county, where we are focusing additional exploration activities.

At the beginning of 2012, our drilling efforts were primarily defined by a vertical Wolfberry program, supplemented with horizontal wells initially focused in the Cline shale. We believe that our acreage in the Permian-Garden City can be produced horizontally, with even stronger economic results, across both the Wolfcamp and Cline shale formations. Within the Wolfcamp, we have three distinct zones; the Upper, Middle and Lower Wolfcamp shales, which together with the Cline shale provide four horizontal targets. During 2012 we drilled and completed 35 horizontal wells confirming production and attractive returns from all four zones. Today, we are increasing our drilling focus towards a horizontal development and exploitation program supported by vertical wells that help us define the horizontal targets. Our proprietary and industry data includes approximately 800 square miles of proprietary/licensed 3D seismic, 11 whole and more than 300 sidewall cores, 23 single-zone tests, more than 130 proprietary petrophysical logs, greater than 13,500 open-hole logs, and 60 completed horizontal wells in the four zones we are currently targeting, providing extensive production and reservoir engineering data as of December 31, 2012. 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 shale plays.

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, 2012, we had successfully drilled and completed 23 horizontal wells in the Upper Wolfcamp, two horizontal wells in the Middle Wolfcamp and one horizontal well in the Lower Wolfcamp. The initial production results from these Middle and Lower Wolfcamp zones appear comparable to our Upper Wolfcamp completions.

Upper Wolfcamp. As of December 31, 2012, we estimated that approximately 60,000 net acres of our Permian-Garden City area had been de-risked for horizontal Upper Wolfcamp development. As of February 28, 2013, we estimated that an additional 20,000 net acres had been de-risked, totaling 80,000 net acres in the Permian-Garden City area. 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 over 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, 2012, we had completed two horizontal wells in the Middle Wolfcamp zone and one horizontal well in the Lower Wolfcamp zone. As of February 28, 2013, we estimated that approximately 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, 2012, we estimated that approximately 70,000 net acres of our Permian-Garden City area had been de-risked for horizontal Cline development. As of February 28, 2013, we estimated that an additional 57,000 net acres had been de-risked, totaling 127,000 net acres in the Permian-Garden City area. In 2012 we successfully drilled and completed 12 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 moving into the horizontal development phase of this identified acreage. We believe the petrophysical data indicates 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 approximately 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 over 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 intend to leverage the knowledge and database we have accumulated from our development of our Permian-Garden City area and apply it to our Permian-China Grove area that we also believe is prospective for the Cline shale. As of December 31, 2012, we held approximately 57,750 net acres in this area, primarily in Mitchell County, Texas, and at the end of 2012 were drilling and completing our first vertical and horizontal wells to begin defining the potential upside of this acreage.

Anadarko Granite Wash

Straddling the Texas/Oklahoma state line, our Granite Wash play extends across a large area in the western part of the Anadarko Basin. As of December 31, 2012, we held 37,322 net acres in Hemphill County, Texas and Roger Mills County, Oklahoma. Currently, we are drilling only horizontal opportunities targeting the liquids-rich Granite Wash formation. By utilizing the whole core data we obtained early in the exploration process, the subsurface information from our vertical wells (and others drilled by industry), and enhanced logging interpretation techniques, we have been able to develop a detailed regional geologic depositional and engineering understanding of the Granite Wash.

Several of the targeted intervals in the Granite Wash are now being developed in a repeatable economic drilling program. The Granite Wash is a conventional play that requires drilling to be done "surgically" to insure that each lateral penetrates the maximum amount of pay in each defined porosity fairway. We continue our exploration efforts by defining additional porosity trends in both deeper and shallower Granite Wash zones, utilizing our large open-hole log database and in-house petrophysical expertise.

Other areas

As of December 31, 2012, we held 44,621 net acres in the Central Texas Panhandle where our operations are currently conducted through our joint venture with ExxonMobil. The prospective zones in this area are relatively shallow (less than 9,500 feet), with a majority being predominately natural gas.

As of December 31, 2012, we held 22,602 net acres in the eastern end of the Anadarko Basin, in Caddo, Grady and Comanche counties, Oklahoma. There are multiple targets to drill in this area, varying in depth between 8,000 feet and 22,000 feet, which are predominantly dry natural gas.

These areas, which we refer to as our "Other Areas", represent approximately 8% of our year ended December 31, 2012 production and approximately 4% of our estimated proved reserves as of December 31, 2012.

New Ventures

In addition to our Permian and Anadarko Granite Wash plays, 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. As of December 31, 2012, we held 88,728 net acres in the Dalhart Basin. Our current exploration activity in this area is concentrated around liquids-rich shale plays that may underlie a significant portion of the entire area. Targeted intervals are considered oil plays at depths of less than 7,000 feet. As of December 31, 2012, we have drilled four gross wells, three vertical and one horizontal in the Dalhart Basin.

In addition, as of December 31, 2012, we held approximately 24,615 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 on Form 10-K, 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 188,632 MBOE as of December 31, 2012, of which 43% were classified as proved developed reserves, and 52% are attributable to oil reserves. The following table presents summary data for each of our core operating areas as of December 31, 2012. Our estimated proved reserves at December 31, 2012 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".

	At December 31, 2012 Proved reserves (MBOE)	% of total	
Area:			
Permian Basin	160,028	85	%
Anadarko Granite Wash	20,172	11	%
Other Areas(1)	8,416	4	%
New Ventures(2)	16	—	%
Total	188,632	100	%

(1) Includes Eastern Anadarko and Central Texas Panhandle.

(2) Includes Dalhart Basin and other New Ventures.

The following table sets forth more information regarding our estimated proved reserves at December 31, 2012 and 2011. Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves at December 31, 2012 and December 31, 2011. The reserve estimates at December 31, 2012 and 2011 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.

	At December 31,	
	2012	2011
Estimated proved reserves:		
Oil and condensate (MBbl)	98,141	56,267
Natural gas (MMcf)	542,946	601,117
Total estimated proved reserves (MBOE)	188,632	156,453
Proved developed producing (MBOE)	76,777	59,631
Proved developed non-producing (MBOE)	4,713	3,564
Proved undeveloped (MBOE)	107,142	93,258
Percent developed	43 %	40 %

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, 2012 and 2011 included in this Annual Report on Form 10-K. 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.

John E. Minton, our Senior Vice President of Reservoir Engineering, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. He has more than 39 years of practical experience with 35 years of this experience being in the estimation and evaluation of reserves. He has been a registered Professional Engineer in the State of Oklahoma since 1982, has a Bachelor of Science degree in Mechanical Engineering, and is a life member in good standing of the Society of Petroleum Engineers. Mr. Minton reports directly to our President and Chief Operating Officer. Reserve 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' reserve 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 93,258 MBOE at December 31, 2011, to 107,142 MBOE at December 31, 2012. During 2012, 5,163 MBOE of proved undeveloped reserves from 83 locations were converted to proved developed reserves. New proved undeveloped reserves of 69,892 MBOE were added during the year, with approximately 80% coming from new horizontal Upper Wolfcamp, Cline and Granite Wash locations, and the balance from vertical deep Wolfberry locations. Negative revisions of 55,837 MBOE were primarily attributable 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. These locations became economically unattractive to develop due to these factors and were replaced by new horizontal and/or oil development opportunities.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2012 reserve report are $2.2 billion. Based on this report, the capital estimated to be spent in 2013, 2014, 2015, 2016 and 2017 to develop the proved undeveloped reserves is $305 million, $358 million, $455 million, $533 million and $512 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, 2012, 2011 and 2010. 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,		
	2012	2011	2010
Production data:			
Oil (MBbl)	4,775	3,368	1,648
Natural gas (MMcf)	39,148	31,711	21,381
Oil equivalents (MBOE)(1)	11,300	8,654	5,212
Average daily production (BOE/D)	30,874	23,709	14,278
Revenues (in thousands):			
Oil	$414,932	$306,481	$126,891
Natural gas	$168,637	$199,774	$112,892
Average sales prices without hedges:			
Benchmark oil ($/Bbl)(2)	$94.20	$95.01	$79.53
Realized oil ($/Bbl)(3)	$86.89	$91.00	$77.00
Benchmark natural gas ($/MMBtu)(2)	$2.80	$4.02	$4.39
Realized natural gas ($/Mcf)(3)	$4.31	$6.30	$5.28
Average price ($/BOE)	$51.65	$58.50	$46.01
Average sales prices with hedges(4):			
Oil ($/Bbl)	$86.69	$88.62	$77.26
Natural gas ($/Mcf)	$5.02	$6.67	$6.32
Average price ($/BOE)	$54.03	$58.93	$50.37
Average cost per BOE:			
Lease operating expenses	$5.96	$5.00	$4.16
Production and ad valorem taxes	$3.33	$3.70	$3.01
Depreciation, depletion and amortization	$21.56	$20.38	$18.69
General and administrative(5)	$5.50	$5.90	$5.93

(1) The volumes presented for the years ended December 31, 2012, 2011 and 2010 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 realized gains and losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting.

(5) General and administrative includes non-cash stock-based compensation of $10.1 million, $6.1 million and $1.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. Excluding stock-based compensation from the above metric results in average general and administrative cost per BOE of $4.61, $5.19 and $5.69 for the years ended December 31, 2012, 2011 and 2010, respectively.

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas at December 31, 2012. 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[1]	Net		
Permian Basin:						
Permian-Garden City	809	60	869	799	92	%
Permian-China Grove	—	—	—	—	—	%
Anadarko Granite Wash	166	25	191	142	74	%
Other Areas[2]	338	11	349	176	50	%
New Ventures[3]	1	1	2	2	98	%
Total	1,314	97	1,411	1,119		

(1) 1,181 of the 1,411 total gross producing wells are Laredo operated.
(2) Includes Eastern Anadarko and Central Texas Panhandle.
(3) 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, 2012 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	89,710	81,921	92,969	63,878	182,679	145,799	56	%
Permian-China Grove	—	—	76,763	57,750	76,763	57,750	—	%
Anadarko Granite Wash	37,946	29,596	14,779	7,726	52,725	37,322	79	%
Other Areas[1]	90,645	60,706	11,356	6,517	102,001	67,223	90	%
New Ventures[2]	760	622	154,210	112,721	154,970	113,343	1	%
Total	219,061	172,845	350,077	248,592	569,138	421,437	41	%

(1) Includes Eastern Anadarko and Central Texas Panhandle.
(2) 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, 2012 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.

	2013		2014		2015		2016	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin:								
Permian-Garden City	50,309	34,669	14,608	10,831	12,026	10,328	640	160
Permian-China Grove	—	—	20,501	16,697	50,450	37,440	5,811	3,613
Anadarko Granite Wash	5,174	2,534	4,798	1,910	1,763	653	320	204
Other Areas(1)	9,763	5,476	1,314	989	280	51	—	—
New Ventures(2)	35,225	11,935	41,458	39,846	62,973	48,898	1,280	930
Total	100,471	54,614	82,679	70,273	127,492	97,370	8,051	4,907

(1) Includes Eastern Anadarko and Central Texas Panhandle.
(2) Includes Dalhart Basin and other New Ventures.

Drilling activity

The following table summarizes our drilling activity for the year ended December 31, 2012, 2011 and 2010. 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.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	199	183.2	260	233.2	294	276.6
Dry	—	—	—	—	2	2.0
Total development wells	199	183.2	260	233.2	296	278.6
Exploratory wells:						
Productive	1	1.0	2	1.4	11	9.3
Dry	1	0.9	—	—	1	1.0
Total exploratory wells	2	1.9	2	1.4	12	10.3

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 more favorable Gulf Coast pricing.

As of December 31, 2012, 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	2013	2014	2015	2016 and beyond
Oil and condensate (MBbl)	53,265	1,800	6,585	9,490	35,390
Natural gas (MMcf)	7,022	970	1,803	2,096	2,153
Total (MBOE)	54,435	1,962	6,886	9,839	35,749

We expect to fulfill our delivery commitments over the next three years with production from our proved developed 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 H in our audited consolidated financial statements included elsewhere in this Annual Report on From 10-K. 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, 2012, 41% 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 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 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 we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory locations 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 and Oklahoma 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 and the Anadarko Granite Wash. While hydraulic fracturing is not required to maintain 41% 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 non-producing and proved undeveloped reserves associated with future drilling, recompletion and refracture stimulation projects, or approximately 59% of our total estimated proved reserves as of December 31, 2012, require hydraulic fracturing.

We have and continue to follow standard industry practices and applicable legal requirements. State and federal regulators (including the U.S. Bureau of Land Management on federal acreage) 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. We are in the process of testing recycled flowback/produced water in our fracing operations, and are evaluating the performance of the limited number of wells in which we have used this process to determine if there is any impact on productivity.

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 could prohibit projects or result in increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing 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. All of the jurisdictions in which we own or operate producing oil and natural gas properties have 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 unitization or 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. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, 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, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. We own interests in properties located onshore in different U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states 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, unitization and pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas wells. Some states have 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 cleanup 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. Some states also maintain 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, particularly natural gas, 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 May 4, 2012, the EPA published a draft UIC Program permitting guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document is designed for use by EPA UIC permit writers, and 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 and Oklahoma, where we maintain acreage, the EPA is encouraging state programs to review and consider use of this permit guidance. The draft guidance document underwent an extended public comment process, which concluded on August 23, 2012. The EPA is presently evaluating the public comments and will likely issue a final guidance document at a later date. 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 final report for public comment and peer review in 2014. 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, and such legislation could be introduced in the current session of Congress. 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. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas. 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. Furthermore, on May 4, 2012, the the United States Department of the Interior ("DOI") issued a draft 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. 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, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or 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 became effective October 15, 2012; however, a number of the requirements did not take immediate effect. The final rule establishes a phase-in period to allow for the manufacture and distribution of required emissions reduction technology. During the first phase, ending December 31, 2014, owners and operators of gas wells must either flare their emissions or use emissions reduction technology called "green completions" technologies already deployed at wells. On or after January 1, 2015, all newly fractured gas wells will be required to use green completions. Controls for certain storage vessels and pneumatic controllers may phase-in over one year beginning on the date the final rule is published in the Federal Register, while certain compressors, dehydrators and other equipment must comply with the final rule immediately or up to three years and 60 days after publication of the final rule, depending on the construction date and/or nature of the unit. We continue to evaluate the EPA's final rule, as it may require changes to our operations, including the installation of new emissions control equipment. 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 from sources within the U.S. between 2012 and 2050, but it was not approved by the U.S. Senate in the 2009-2010 legislative session. Congress is likely to continue to consider similar bills. Moreover, almost 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, 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 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 manufactured in model years 2012-2016; however, it does not require immediate reductions in GHG emissions. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011, although it remains the subject of several pending lawsuits filed by industry groups. The

tailoring rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the tailoring rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the tailoring rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the tailoring rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Finally, in October 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. On March 27, 2012, the EPA issued a proposed rule establishing carbon pollution standards for new fossil-fuel-fired electric utility generating units. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is presently evaluating the public comments and is expected to issue a final rule at a later date. The EPA plans to implement GHG emissions standards for refineries at a later date.
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 2011 or 2012.
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 relating to Iran during the period covered by the report. Neither we nor any of our controlled affiliates or subsidiaries 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.
During 2012, Warburg Pincus was, and currently is, our largest stockholder (owning approximately 68% of our outstanding common stock as of the date of this report) and two members of our board of directors are with Warburg Pincus. Consequently Warburg Pincus was our “affiliate” during the reporting period. Moreover, Warburg Pincus has informed us that it owns more than 10% of the equity interests of, and the right to designate members of the board of directors of, Bausch & Lomb Incorporated (“Bausch & Lomb”). Consequently, Bausch & Lomb may be viewed as our “affiliate” under Rule 12b-2. Warburg Pincus has informed us that Bausch & Lomb has provided it with the below information relevant to Section 13(r). The disclosure relates solely to activities conducted by Bausch & Lomb and its non-U.S. affiliates and does not relate to any activities conducted by us or Warburg Pincus and does not involve our or Warburg Pincus' management. Neither us nor Warburg Pincus is representing to the accuracy or completeness of such information and undertake no obligation to correct or update this information.
“Bausch & Lomb, an eye health company, makes sales of human healthcare products to benefit patients in Iran under licenses issued by the U.S. Department of the Treasury's Office of Foreign Assets Control (“OFAC”). In 2012, Bausch & Lomb was granted licenses by OFAC, extending to its foreign affiliates doing business in Iran. Before the U.S. Government extended OFAC sanctions to entities controlled by U.S. persons in October 2012, it was permissible under U.S. law for non-U.S. affiliates to engage in sales to Iranian customers under limited circumstances. In accordance with these requirements, during the first three quarters of 2012, certain of Bausch & Lomb's non U.S. affiliates engaged in sales to Iran from its Surgical - Consumables business, which includes certain intraocular lenses and other products used to help people retain or regain sight. Its non-U.S. affiliate, Technolas Perfect Vision GmbH (“TPV”), which sells ophthalmic surgery systems and related products used in connection with refractive and cataract surgery, also engaged in sales to Iran. These sales were all conducted through a distributor, which also engaged in certain registration and licensing activities with the Iranian government involving Bausch & Lomb's products. The Iranian distributor is not listed on any U.S. sanctions lists and is not a government-owned entity. However, the downstream customers of this distributor included public hospitals, which may be owned or controlled directly or indirectly by the Iranian government. The entire gross revenues attributable to Bausch & Lomb's Surgical - Consumables business not conducted pursuant to an OFAC license in Iran during 2012 were US $5,058,000 and the gross profits were US$2,690,000. The entire gross revenues attributable to TPV's sales to Iran during 2012 not under OFAC license were €1,738,900 and the gross profits were €958,624. Bausch & Lomb does not have sufficient information to specify what proportion of these sales may relate to Iranian government end customers of its distributor. The purpose of Bausch & Lomb's Iran-related activities is to provide access to important and sight-saving products to surgeons and patients in Iran, and to improve the eye healthcare of the Iranian people. For this reason, Bausch & Lomb and its affiliates plan to continue their existing activities and operations in Iran; however, as noted above, all of this business (including business conducted by non-U.S. companies) is conducted pursuant to licenses issued by OFAC.”
Employees

As of December 31, 2012, we had 266 full-time employees. We also employed a total of 16 contract personnel who assist our full-time employees with respect to specific tasks and perform various field and other services. Our future success will depend partially on our ability to 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 1800, Tulsa, Oklahoma 74119, and the phone number at this address is (918) 513-4570. We also own or lease field offices in Midland and Dallas, Texas.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. 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 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 1800, Tulsa, Oklahoma 74119. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K. 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 on Form 10-K, 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 substantial or 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.

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. 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 and natural gas;
- the price and quantity of imports of foreign oil and natural gas, including liquefied natural gas;
- 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 and Russia;
- the level of global oil and natural gas exploration and production;
- future regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells;
- the level of global oil and natural gas inventories;
- 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 and natural gas 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. Substantial decreases in oil and natural gas prices would 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. As a result, a substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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 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.

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 exploitation, exploration, 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 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." 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:

- 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;
- declines in oil and natural gas prices;
- limited availability of financing at acceptable rates;
- title problems; and
- limitations in the market for oil and natural gas.

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

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons, particularly natural gas, 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. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling, recompletion and refracture stimulation projects, or approximately 59% of our total estimated proved reserves as of December 31, 2012, will 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 May 4, 2012, the EPA published a draft UIC Program guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document is designed for use by employees of the EPA that draft the UIC permits and 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 and Oklahoma, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned draft guidance. The draft guidance underwent an extended public comment process, which concluded on August 23, 2012. The EPA is presently evaluating the public comments and will likely issue a final guidance document at a later date. 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 final report for public comment and peer review in 2014.

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 became effective October 15, 2012; however, a number of the requirements did not take immediate effect. The rule established a phase-in period to allow for the manufacture and distribution of required emissions reduction technology. During the first phase, ending December 31, 2014, owners and operators of gas wells must either flare their emissions or use emissions reduction technology called "green completions" technologies already deployed at wells. On or after January 1, 2015, all newly fractured gas wells will be required to use green completions. Controls for certain storage vessels and pneumatic controllers may phase-in over one year beginning August 16, 2012, while certain compressors, dehydrators and other equipment must comply with the final rule immediately or up to three years and 60 days after the August 16, 2012 publication of the final rule, depending on the construction date and/or nature of the unit. We continue to evaluate the EPA's final rule, as it may require changes to our operations, including the installation of new emissions control equipment. Furthermore, on May 4, 2012, the DOI issued a draft 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. 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. 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. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas. 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 Railroad Commission of Texas and the public beginning February 1, 2012. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from conventional or 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.

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 on Form 10-K represent estimates. Reserve 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 reserve estimates. Our negative revisions of 55,837 MBOE in 2012 were primarily the result of lower prices and increased well costs that caused the locations to become uneconomic.
Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which decrease earnings or result in losses through higher depreciation, depletion and amortization 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 O.4 in our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

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. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our identified potential drilling 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.

If commodity prices 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. We may 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 B.7 to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional information.

Unless we replace our oil and natural gas reserves, 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 effective prices consistent with those we have received to date and oil and natural gas prices do not improve, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2012, we have entered into hedge contracts for approximately 4.4 million Bbls of our crude oil production and 56.3 million MMBtu of our natural gas production for settlement between January 2013 and December 2015. We are currently realizing a benefit from these hedge positions. If future oil and natural gas prices remain comparable to current prices, we expect that this benefit will decline materially over the life of the hedges, which cover decreasing volumes at declining prices through 2015. 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—Commodity derivative financial instruments."

Our derivative activities could result in financial losses or could reduce our earnings.

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 collars, puts and basis swaps. In accordance with applicable accounting principles, we are required to record our derivative financial instruments at fair market value, and they are included on our consolidated balance sheet as assets or liabilities and in our consolidated statement of operation as realized or unrealized gains. Losses 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, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

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 (approximately $30.9 million at December 31, 2012) and the sale of our oil and natural gas production (approximately $48.4 million in receivables at December 31, 2012), 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 approximately 34% of our total oil and natural gas revenues for the year ended December 31, 2012. We do not require our customers to post collateral. 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.

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:

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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;

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- 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.

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 on Form 10-K, 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 data 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 visualization techniques 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 new, unproven and unconventional, which can lessen its effectiveness, at least in the near term, and increase our costs. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in our returns. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

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

Market conditions, the unavailability of satisfactory oil and natural gas gathering, processing or transportation arrangements or operational impediments may adversely affect our access to oil, natural gas and natural gas liquids markets or delay our production.

The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines, trucking and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, trucking and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of oil and natural gas pipeline, trucking, gathering system or processing capacity. In addition, if oil or natural gas quality specifications for the third party oil or natural gas pipelines with which we connect change so as to restrict our ability to transport oil or natural gas, our access to oil and natural gas markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

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 2012, West Texas and Oklahoma 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 financial condition, results of operations and cash flows.

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" for a further description of the laws and regulations that affect us.

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.

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. Historically, 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, the high level of drilling activity in the Permian Basin and Anadarko Granite Wash has resulted in equipment shortages in those areas. We committed to several short-term drilling contracts with various third parties in order to complete various drilling projects. An early termination clause in these contracts requires us to pay significant penalties to the third party should we cease drilling efforts. These penalties could significantly impact our financial statements upon contract termination. As a result of these commitments, approximately $1.6 million in stacked rig fees were incurred in 2009. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. The 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.

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" ("GHGs"), 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 from sources within the U.S. between 2012 and 2050 but was not approved by the Senate in the 2009-2010 legislative session. Congress is likely to continue to consider similar bills. Moreover, almost 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 manufactured in model years 2012-2016; however, it does not require immediate reductions in GHG emissions. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011, although it remains the subject of several pending lawsuits filed by industry groups. The tailoring rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the tailoring rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the tailoring rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the tailoring rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Finally, in October 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. On March 27, 2012, the EPA issued a proposed rule establishing carbon pollution standards for new fossil-fuel-fired electric utility generating units. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is presently evaluating the public comments and is expected to issue a final rule at a later date. The EPA plans to implement GHG emissions standards for refineries in November 2012.

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.

The derivatives reform legislation adopted by Congress could have a material adverse impact on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"), which, among other provisions, requires more reporting requirements as well as establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market, was signed into law on July 21, 2010. The new legislation required the Commodities Futures Trading Commission ("CFTC") and the SEC to promulgate rules implementing the new legislation within 360 days from the date of enactment. These rules have been adopted and those rules which have not been vacated and are not yet effective will take effect, depending on the rule, on April 10, 2013, May 1, 2013 or July 1, 2013.

In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. This rule was vacated and remanded to the CFTC for further proceedings by order of the United States District Court for the District of Columbia, Judge Robert L. Wilkins, on September 28, 2012. The CFTC may issue another position limit rule after conducting such further proceedings and such rule may or may not be similar to the vacated rule and contain an exemption from position limits for certain bona fide hedging transactions or positions. The CFTC has also issued final rules further defining "swap," "swap dealer" and "major swap participant" and specifying the reporting and other requirements for "non-financial entities" to elect the exception to the clearing requirement under the Commodity Exchange Act ("CEA"). We qualify as a non-financial entity under the CEA and intend to comply with the reporting and other requirements of the exception and utilize the exception. Although the rules will not impose clearing requirements on us, they will impose additional reporting and recordkeeping requirements on us and clearing, capital, margin and reporting and recordkeeping on swap dealers and major swap participants and will also require certain of our potential swap counterparties to conduct their swap activities through affiliates which may be less creditworthy than existing potential swap counterparties. The rules and, if issued, a new position limit rule could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our potential exposure to less creditworthy counterparties. If we reduce our use of derivatives or commodity prices decline as a result of the legislation 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 and our results of operations.

Competition in the oil and natural gas industry is intense, making it more 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 will 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. The cost to attract and retain qualified personnel has increased due to competition and may increase substantially in the future. 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.

The loss of senior management or technical personnel could materially 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 A. 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, 2012, Warburg Pincus owned approximately 68% 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 sell all or a substantial portion of or otherwise reduce its ownership interest in us. 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 materially 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.

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 and Anadarko Granite Wash. At December 31, 2012, substantially all of our total estimated proved reserves were attributable to properties located in these areas. 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. In addition, if we are successful in divesting our non-Permian Basin assets, these risks associated with concentration will increase.

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 intensify competition during those 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.

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 December 31, 2012, we have approximately $660 million of additional borrowing capacity 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 $825 million available on our senior secured credit facility would result in increased annual interest expense of approximately $8.3 million and a corresponding decrease in our net income before taking into account the effects of increased interest rates on the value of our interest rate contracts. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in our cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We 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 may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to incorporate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our 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 approximately $1.8 million and for each of the years ended December 31, 2007, 2008 and 2009 of approximately $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."

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. At December 31, 2012, four customers accounted for 10% or greater of our oil and natural gas sales receivables: 25.7%, 13.7%, 13.0% and 10.7%. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our oil and natural gas hedging arrangements expose us to credit risk in the event of nonperformance by counterparties. Current economic circumstances may further increase these risks.

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 borrowings will be available to us under our senior secured credit facility or otherwise 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 December 31, 2012, we had total long-term indebtedness of approximately $1.2 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.

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

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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.

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

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 your 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;
- at such time as Warburg Pincus no longer beneficially owns more than 50% of our outstanding common stock, any action by stockholders may no longer be effected by written consent of the stockholders;
- at such time as Warburg Pincus no longer beneficially owns more than 50% of our outstanding common stock, our board of directors will be divided into three classes with each class serving staggered three year terms;
- 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; 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 concentration of our capital stock ownership among our largest stockholder will limit your ability to influence corporate matters.

As of December 31, 2012, Warburg Pincus owned approximately 68% 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.

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.

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

In the future, we may issue securities to raise cash for acquisitions. 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, or 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.

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
2012:		
First Quarter	$26.80	$20.84
Second Quarter	$26.63	$18.79
Third Quarter	$24.09	$21.10
Fourth Quarter	$22.37	$17.11
2011:		
Fourth Quarter[1]	$22.31	$17.25

(1) Represents the period from December 15, 2011, the date on which our common stock began trading on the NYSE, through December 31, 2011.

On March 8, 2013, the last sale price of our common stock, as reported on the NYSE, was $17.88 per share.

Holders. As of March 8, 2013, there were approximately 24 holders of record of our common stock. The number of record holders does not include holders of shares in "street names" or persons, partnerships, associations, corporations or other entities identified in security position listings maintained by depositories.

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 Operation—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. 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, 2012, as compared to the returns on the Standard and Poor's 500 Index ("S&P 500") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P"). The comparison was prepared based upon the following assumptions:

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

Item 6. Selected Historical Financial Data

The selected historical consolidated financial data presented below is not intended to replace our consolidated financial statements. You should read the following data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report on Form 10-K. We believe that the assumptions underlying the preparation of our financial statements are reasonable. The financial information included in this Annual Report on Form 10-K may not be indicative of our future results of operations, financial position and 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, 2012, 2011 and 2010 and the balance sheet data as of December 31, 2012 and 2011 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K. The historical financial data for the year ended December 31, 2009 and 2008 and the balance sheet data as of December 31, 2010, 2009 and 2008 are derived from our audited financial statements not included in this Annual Report on Form 10-K.

	For the years ended December 31,				
(in thousands, except per share data)	2012	2011	2010	2009	2008[(1)]
Statement of operations data:					
Total revenues	$588,080	$510,270	$242,000	$96,574	$74,187
Total costs and expenses	416,300	308,371	169,018	350,103	350,653
Operating income (loss)	171,780	201,899	72,982	(253,529)	(276,466)
Non-operating income (expense), net	(77,177)	(36,971)	(12,546)	(4,972)	30,702
Income (loss) before income taxes	94,603	164,928	60,436	(258,501)	(245,764)
Net income (loss)	61,654	105,554	86,248	(184,495)	(192,047)
Net income per common share:					
Basic	$0.49	$0.98			
Diluted	$0.48	$0.98			

(1) The year ended December 31, 2008 contains the results of operations for the acquisition of properties from Linn Energy beginning August 15, 2008, the closing date of the property acquisition.

	At December 31,				
(in thousands)	2012	2011	2010	2009	2008
Balance sheet data:					
Cash and cash equivalents	$33,224	$28,002	$31,235	$14,987	$13,512
Net property and equipment	2,113,891	1,378,509	809,893	396,100	350,702
Total assets	2,338,304	1,627,652	1,068,160	625,344	578,387
Current liabilities	262,068	214,361	150,243	79,265	101,864
Long-term debt	1,216,760	636,961	491,600	247,100	148,600
Stockholders' equity	831,723	760,013	411,099	289,107	318,364

(in thousands)	For the years ended December 31, 2012	2011	2010	2009	2008
Other financial data:					
Net cash provided by operating activities	$376,776	$344,076	$157,043	$112,669	$25,332
Net cash used in investing activities	(940,751)	(706,787)	(460,547)	(361,333)	(490,897)
Net cash provided by financing activities	569,197	359,478	319,752	250,139	472,140

(in thousands, unaudited)	For the years ended December 31, 2012	2011	2010	2009	2008
Adjusted EBITDA[1]	$452,569	$388,446	$194,502	$104,908	$49,305

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income (loss) 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, depreciation, depletion and amortization, impairment of long-lived assets, write-off of deferred loan costs and other, gains or losses on sale of assets, unrealized gains or losses on derivative financial instruments, realized losses on interest rate swaps, realized gains or losses on canceled derivative financial instruments, 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 and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors, 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 methods of calculating Adjusted EBITDA and our measurements of Adjusted EBITDA for financial reporting and compliance under our debt agreements differ.

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

	For the years ended December 31,				
(in thousands, unaudited)	2012	2011	2010	2009	2008
Net income (loss)	$61,654	$105,554	$86,248	$(184,495)	$(192,047)
Plus:					
Interest expense	85,572	50,580	18,482	7,464	4,410
Depreciation, depletion and amortization	243,649	176,366	97,411	58,005	33,102
Impairment of long-lived assets	—	243	—	246,669	282,587
Write-off of deferred loan costs	—	6,195	—	—	—
Loss on disposal of assets	52	40	30	85	2
Unrealized losses (gains) on derivative financial instruments	16,522	(20,890)	11,648	46,003	(27,174)
Realized losses on interest rate derivatives	2,115	4,873	5,238	3,764	278
Non-cash stock-based compensation	10,056	6,111	1,257	1,419	1,864
Income tax expense (benefit)	32,949	59,374	(25,812)	(74,006)	(53,717)
Adjusted EBITDA	$452,569	$388,446	$194,502	$104,908	$49,305

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes thereto appearing elsewhere in this Annual Report on Form 10-K. 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 which 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, 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 on Form 10-K, 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."

Executive overview

We are an independent energy company focused on the exploration, development and acquisition of oil and natural gas properties primarily in the Permian and Mid-Continent regions of the United States. Laredo Petroleum, Inc. was founded in October 2006 to explore, develop and operate oil and natural gas properties and has grown rapidly through its drilling program and by making strategic acquisitions and joint ventures. On July 1, 2011, we completed the acquisition of Broad Oak Energy, Inc. (“Broad Oak”), whereby Broad Oak became a wholly-owned subsidiary of Laredo Petroleum, Inc., and its name was changed to Laredo Petroleum—Dallas, Inc. This acquisition was considered a combination of entities under common control and the historical and financial operating data presented herein are shown on a consolidated basis. In December 2011, we completed the Corporate Reorganization and IPO. See Note A to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional information regarding the Corporate Reorganization and the IPO.

Our financial and operating performance for the year ended December 31, 2012 included the following:

- Oil and natural gas sales of approximately $583.6 million, compared to approximately $506.3 million for the year ended December 31, 2011;
- Average daily production of 30,874 BOE/D, compared to 23,709 BOE/D for the year ended December 31, 2011;
- Estimated net proved reserves of 188,632 MBOE as of December 31, 2012, compared to 156,453 MBOE as of December 31, 2011; and
- Adjusted EBITDA (a non-GAAP financial measure) of $452.6 million, compared to $388.4 million for the year ended December 31, 2011.

Recent Developments

In February 2013, we announced we are exploring options to potentially divest certain assets located outside the Permian Basin. These assets consist of our Anadarko Granite Wash properties (approximately 11% of our estimated net proved reserves as of year-end) as well as properties owned in the Central Texas Panhandle (Hansford, Hutchinson, Ochiltree and Roberts counties in Texas) and the Eastern Anadarko Basin (Caddo, Grady and Comanche counties in Oklahoma) (collectively, approximately 4% of our estimated net proved reserves at such time). There can be no assurance that the divestiture of any assets will be completed.

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 upsides in assets.

As noted above, on July 1, 2011, we consummated the acquisition of Broad Oak for consideration consisting of (i) cash payments totaling $82.0 million to certain members of management and employees, (ii) equity issuances of 86.5 million preferred Laredo Petroleum, LLC units to Warburg Pincus, (iii) equity issuances of 2.4 million preferred Laredo

Petroleum, LLC units to certain directors and management of Broad Oak and (iv) repayment of the $265.4 million of outstanding debt under the Broad Oak credit facility. Immediately following the consummation of such transaction, Laredo Petroleum, LLC assigned 100% of its ownership interest in Broad Oak to Laredo Petroleum, Inc. as a contribution to capital.

Core areas of operations

The oil and liquids-rich Permian Basin and the liquids-rich Anadarko Granite Wash are characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of December 31, 2012, we had assembled 203,549 net acres in the Permian Basin and 37,322 net acres in the Anadarko Granite Wash and had an interest in 1,411 gross producing wells. Based on a report by Ryder Scott, our independent reserve engineers, as of such date, we operated wells that represent approximately 95% of the value of our proved developed oil and natural gas reserves.

Reserves and pricing

Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves, reported on a two-stream basis, at December 31, 2012, 2011 and 2010. As of December 31, 2012, we had 188,632 MBOE of estimated net proved reserves as compared to 156,453 MBOE of estimated net proved reserves at December 31, 2011 and 136,560 MBOE of estimated net proved reserves at December 31, 2010.

Our results of operations are heavily influenced by commodity prices. 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. 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 drilling projects, as well as the economic valuation and economic recovery of oil and natural gas 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. The unweighted arithmetic average first-day-of-the-month index prices for the prior 12 months were $91.21 per Bbl for oil and $2.63 per MMBtu for natural gas at December 31, 2012, $92.71 per Bbl for oil and $3.99 per MMBtu for natural gas at December 31, 2011 and $75.96 per Bbl for oil and $4.15 per MMBtu for natural gas at December 31, 2010. The prices used to estimate proved reserves for all periods did not give effect to 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 allowed us to offset a portion of the changes 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 derived from the sale of oil and natural gas within the continental United States and do not include the effects of derivatives. For the year ended December 31, 2012, our revenues are comprised of sales of approximately 70% oil, 29% gas and 1% for transportation, gathering, drilling and production. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Principal components of our cost structure

Lease operating and natural gas transportation and treating expenses. These are daily costs incurred to bring oil and natural gas out of the ground and to the 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 assessed based on a flat rate per oil or natural gas equivalent produced on our properties located in Texas.

Drilling and production. These are costs incurred to maintain facilities that support our drilling activities.

General and administrative. 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 and legal compliance.

Stock-based compensation. These are costs incurred for compensation expense related to employee stock and option awards granted which have been recognized on a straight-line basis over the vesting period associated with the award.

Depreciation, depletion 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 proved 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 unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved 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.

Impairment expense. This is the cost to reduce proved oil and natural gas properties to the calculated full cost ceiling value and the write-downs of our materials and supplies inventory, consisting of pipe and well equipment, to the lower of cost or market value at the end of the respective period.

Other income (expense)

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

Realized and unrealized gain (loss) on interest rate derivative instruments. We utilize 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 unrealized gains and losses associated with our open interest rate derivative contracts as interest rates change and interest rate contracts expire or new ones are entered into, and (ii) our realized gains and losses on the settlement of these interest rate contracts. We classify these gains and losses as operating activities in our consolidated statements of cash flows.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our senior secured credit facility, our senior unsecured notes and, prior to its termination on July 1, 2011, the Broad Oak credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We have entered into various interest rate derivative contracts to mitigate the effects of interest rate changes. We do not designate these derivative contracts as hedges and therefore hedge accounting treatment is not applicable. Realized and unrealized 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 deferred financing 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.

Income tax expense. Income taxes in our financial statements are generally presented on a "consolidated" basis. However, U.S. tax laws do not allow tax losses of one entity to offset income and losses of another entity until after the consummation of the Broad Oak acquisition on July 1, 2011. As such, the financial accounting for the income tax consequences of each taxable entity is calculated separately for all periods prior to July 1, 2011.

Laredo Petroleum Holdings, Inc. and its subsidiaries are subject to federal and state corporate income taxes. These 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. 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.

Results of operations
For the year ended December 31, 2012 as compared to the year ended December 31, 2011, and for the year ended December 31, 2011 as compared to the year ended December 31, 2010
Production, revenue and pricing

The following table sets forth information regarding production, revenue and average sales prices per BOE for the periods presented:

	For the years ended December 31,		
	2012	2011	2010
Production data:			
Oil (MBbl)	4,775	3,368	1,648
Natural gas (MMcf)	39,148	31,711	21,381
Oil equivalents (MBOE)(1)	11,300	8,654	5,212
Average daily production (BOE/D)(1)	30,874	23,709	14,278
% Oil	42 %	39 %	32 %
Revenues (in thousands):			
Oil	$414,932	$306,481	$126,891
Natural gas	168,637	199,774	112,892
Natural gas transportation and treating	4,511	4,015	2,217
Total revenues	$588,080	$510,270	$242,000
Average sales prices:			
Oil, realized(2) ($/Bbl)	$86.89	$91.00	$77.00
Natural gas, realized(2) ($/Mcf)	4.31	6.30	5.28
Average Price, realized ($/BOE)	51.65	58.50	46.01
Oil, hedged(3) ($/Bbl)	86.69	88.62	77.26
Natural gas, hedged(3) ($/Mcf)	5.02	6.67	6.32
Average Price, hedged ($/BOE)	54.03	58.93	50.37

(1) The volumes presented are based on actual results and are not calculated using the rounded numbers presented in the table above.
(2) Realized crude oil and natural gas prices are the actual prices realized at the wellhead after all adjustments for NGL content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price at the wellhead.
(3) Hedged prices reflect the after effect of our commodity hedging transactions on our average sales prices. Our calculation of such after effects include realized gains and losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting. See Note F.4 to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional information regarding our realized gains and losses on commodity derivatives.

The changes in volumes and prices shown in the table above caused the following changes to our oil and natural gas revenue between the years ended December 31, 2010 and 2011 and 2012:

(in thousands)	Oil	Natural gas	Total net dollar effect of change
2010 Revenue	$126,891	$112,892	$239,783
Effect of changes in price	47,152	32,345	79,497
Effect of changes in volumes	132,440	54,542	186,982
Other	(2)	(5)	(7)
2011 Revenue	$306,481	$199,774	$506,255
Effect of changes in price	(19,627)	(77,904)	(97,531)
Effect of changes in volumes	128,032	46,848	174,880
Other	46	(81)	(35)
2012 Revenue	$414,932	$168,637	$583,569

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 approximately $77.3 million, or 15%, for the year ended December 31, 2012 as compared to the year ended December 31, 2011 is largely due to a 42% increase in oil production and a 23% increase in natural gas production volumes attributable mainly to our Permian and Anadarko Granite Wash areas, which were offset by lower prices received for oil and natural gas. The total increase in oil and natural gas revenues of approximately $266.5 million, or 111%, for the year ended December 31, 2011 as compared to the year ended December 31, 2010 is largely due to a 104% increase in oil production and a 48% increase in natural gas production volumes as well as an increase in both oil and natural gas prices realized for the year.

Natural gas transportation and treating. Our revenues related to natural gas transportation and treating increased by $0.5 million during the year ended December 31, 2012 as compared to the year ended December 31, 2011 and increased by $1.8 million during the year ended December 31, 2011 as compared to the year ended December 31, 2010. These increases were due to the sale of oil condensate from our pipeline assets during each respective period, which occurs on an infrequent basis, as well as an increase in the volumes transported through our pipeline.

Costs and expenses

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

	For the years ended December 31,		
(in thousands except for per BOE data)	2012	2011	2010
Costs and expenses:			
Lease operating expenses	$67,325	$43,306	$21,684
Production and ad valorem taxes	37,637	31,982	15,699
Natural gas transportation and treating	1,468	977	2,501
Drilling and production	2,915	3,817	340
General and administrative(1)	62,106	51,064	30,908
Accretion of asset retirement obligations	1,200	616	475
Depreciation, depletion and amortization	243,649	176,366	97,411
Impairment expense	—	243	—
Total costs and expenses	$416,300	$308,371	$169,018
Average costs per BOE:			
Lease operating expenses	$5.96	$5.00	$4.16
Production and ad valorem taxes	3.33	3.70	3.01
General and administrative(1)	5.50	5.90	5.93
Depreciation, depletion and amortization	21.56	20.38	18.69
Total	$36.35	$34.98	$31.79

(1) General and administrative includes non-cash stock-based compensation of $10.1 million, $6.1 million and $1.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. Excluding stock-based compensation from the above metric results in general and administrative cost per BOE of $4.61, $5.19 and $5.69 for the years ended December 31, 2012, 2011 and 2010, respectively.

Lease operating expenses. Lease operating expenses, which include workover expenses, increased by $24.0 million, or 55%, compared to a 31% increase in production, for the year ended December 31, 2012 compared to 2011, respectively. The increases were primarily due to an increase in exploration and development activity, which resulted in additional producing wells during the year ended December 31, 2012 compared to 2011. The increase in well count also led to increases in routine repairs and maintenance. On a per-BOE basis, lease operating expenses increased in total to $5.96 per BOE at December 31, 2012 from $5.00 per BOE at December 31, 2011. The majority of the increase is mainly due to implementation of best practices with respect to workover operations. Those practices will result in longer term well tubing integrity which we expect will improve overall well performance and production in the long term in addition to a decrease in unit lease expenses as a result of reduced well tubing failures.

Lease operating expenses, which include workover expenses, increased by $21.6 million, or 100%, compared to a 66% increase in production, for the year ended December 31, 2011 compared to 2010, respectively. The increase was primarily due to an increase in drilling activity, which resulted in additional producing wells during 2011 compared to 2010. On a per-BOE basis, lease operating expenses increased in total to $5.00 per BOE at December 31, 2011 from $4.16 per BOE at December 31, 2010. The majority of the increase is due to approximately $3.5 million in additional workover expenses incurred during 2011 as compared to the same period in 2010 as market conditions for oil and natural gas became more favorable.

Production and ad valorem taxes. Production and ad valorem taxes increased to approximately $37.6 million for the year ended December 31, 2012 from $32.0 million for the year ended December 31, 2011, an increase of $5.7 million, or approximately 18%. Our ad valorem taxes have increased primarily as a 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 2011 and 2012 drilling activity in our Permian and Anadarko Granite Wash areas. The average realized prices excluding derivatives for the year ended December 31, 2012 were $86.89 per Bbl for oil and $4.31 per Mcf for gas as compared to $91.00 per Bbl for oil and $6.30 per Mcf for gas for the year ended December 31, 2011.

Production and ad valorem taxes increased to approximately $32.0 million for the year ended December 31, 2011 from $15.7 million for the year ended December 31, 2010, an increase of $16.3 million, or approximately 104%, primarily due to the increase in market prices (not including the effects of hedging), as well as a significant increase in production for 2011 as compared to the same period in 2010. The average realized prices excluding derivatives for the year ended December 31, 2011 were $91.00 per Bbl for oil and $6.30 per Mcf for gas as compared to $77.00 per Bbl for oil and $5.28 per Mcf for gas for the year ended December 31, 2010.

Drilling and production. Drilling and production costs decreased to approximately $2.9 million for the year ended December 31, 2012 from $3.8 million for the year ended December 31, 2011 as a result of decreased maintenance costs. Drilling and production costs increased to approximately $3.8 million for the year ended December 31, 2011 from $0.3 million for the year ended December 31, 2010 as a result of increased maintenance costs related to the increase in drilling during 2011 as compared to 2010.

General and administrative ("G&A"). G&A expense, excluding stock-based compensation, increased to approximately $52.1 million at December 31, 2012 from $45.0 million at December 31, 2011, an increase of $7.1 million, or 16%. Increase is primarily due to approximately $6.4 million in additional salary and benefits due to the growth of our business and employee base. Additionally, the issuance of our cash-settled performance unit liability awards in February 2012, which are revalued at the end of each reporting period using a Monte Carlo simulation, accounted for approximately $1.8 million of the total increase. These increases were partially offset by a decrease in legal and professional fees of approximately $2.1 million for the year ended December 31, 2012, as we incurred higher fees in 2011 related to the issuance of our 2019 senior unsecured notes in January 2011 and October 2011, the acquisition of Broad Oak in July 2011 and our IPO in December 2011. The remaining change is made up of smaller increases in a number of areas such as vehicle expenses, insurance expenses and computer and software costs that are largely a result of increasing our workforce and growing our business. On a per-BOE basis, G&A expense, excluding stock-based compensation, decreased to $4.61 per BOE during the year ended December 31, 2012 from $5.19 per BOE at December 31, 2011. This decrease was a result of a significant increase in production during the year ended December 31, 2012 as compared to the year ended December 31, 2011.

G&A expense, excluding stock-based compensation, increased to approximately $45.0 million at December 31, 2011 from $29.7 million at December 31, 2010, an increase of $15.3 million, or 52%. Increases in professional fees incurred relating to the issuance of our 2019 senior unsecured notes, the Broad Oak acquisition, the filing of a registration statement relating to our 2019 senior unsecured notes with the SEC and other matters accounted for approximately $7.4 million, or 48%, of the change in G&A, as well as approximately $7.2 million in additional salary, benefits and bonus expenditures due to the Broad Oak acquisition and the growth of our business and employee base. On a per-BOE basis, G&A expense, excluding stock-based compensation, decreased to $5.19 per BOE during the year ended December 31, 2011 from $5.69 per BOE at December 31, 2010. This decrease was a result of a significant increase in production during the year ended December 31, 2011 as compared to the year ended December 31, 2010. Additionally, on a per-BOE basis, excluding the costs of the Broad Oak acquisition G&A expense was approximately $4.22 per BOE for the year ended December 31, 2011.

Stock-based compensation. Stock-based compensation increased to approximately $10.1 million at December 31, 2012 from $6.1 million at December 31, 2011, an increase of approximately $3.9 million due largely to the issuance of 932,084 restricted stock awards and 602,948 non-qualified restricted stock options during 2012.

Stock-based compensation increased to approximately $6.1 million at December 31, 2011 from $1.3 million at December 31, 2010, an increase of approximately $4.8 million. Approximately $4.1 million of this increase was attributed largely to new series of units issued in conjunction with the Broad Oak acquisition in the third quarter of 2011. On December 19, 2011, as a result of our Corporate Reorganization, the outstanding units in Laredo Petroleum, LLC that had been previously issued to management, directors and employees were exchanged for 2,500,807 vested and 912,038 unvested shares of common stock in Laredo Petroleum Holdings, Inc. The fair value of the unit awards immediately prior to the exchange was determined to be equal to the fair value of the common shares immediately after the exchange and as such, the basis in the former unvested units was carried over to the unvested shares of common stock. This resulted in no additional incremental compensation cost being recognized at the date of conversion.

We have a 2011 Omnibus Equity Incentive Plan, which allows for the issuance of restricted stock awards, restricted stock option awards and performance units to current and prospective directors, officers, employees, consultants and advisors. In February 2013, we issued 1,099,256 restricted stock awards, 1,018,849 stock options and 58,291 performance units to employees and officers and will record compensation expense related to these issuances in accordance with generally accepted accounting principles in the United States of America ("GAAP") in future periods. See Note N to our audited consolidated financial statements included elsewhere in the Annual Report on Form 10-K for additional information.

Depreciation, depletion and amortization ("DD&A"). DD&A increased to approximately $243.6 million at December 31, 2012 from $176.4 million at December 31, 2011 and $97.4 million at December 31, 2010.
The following table provides components of our DD&A expense for the years periods presented:

	For the years ended December 31,		
(in thousands except for per BOE data)	2012	2011	2010
Depletion of proved oil and natural gas properties	$237,130	$171,517	$93,815
Depreciation of pipeline assets	3,191	2,466	1,982
Depreciation of other property and equipment	3,328	2,383	1,614
DD&A	$243,649	$176,366	$97,411
DD&A per BOE	$21.56	$20.38	$18.69

The increases in depletion of proved oil and natural gas properties of $65.6 million and $1.16 per BOE for the year ended December 31, 2012 compared to 2011, and increases of $77.7 million and $1.82 per BOE for the year ended December 31, 2011 compared to 2010 resulted primarily from (i) decreases in the natural gas price between periods utilized to determine proved reserves, (ii) increased net book value on new reserves added, (iii) higher total production levels and (iv) increased capitalized costs for new wells completed in 2012. We expect depletion of proved oil and natural gas properties to continue to increase as our focus remains on drilling higher-valued oil-rich assets.
Impairment expense. We incurred impairment expense of approximately $0.2 million for the year ended December 31, 2011 to reflect our materials and supplies inventory at the lower of cost or market value calculated as of December 31, 2011. It was determined for the years ended December 31, 2012 and 2010, that a lower of cost or market adjustment was not needed for materials and supplies.
We evaluate the impairment of our oil and natural gas properties on a quarterly basis according to the full cost method prescribed by the SEC. If the carrying amount exceeds the calculated full cost ceiling, we reduce the carrying amount of the oil and natural gas properties to the calculated full cost ceiling amount, which is determined to be their estimated fair value. For the years ended December 31, 2012, 2011 and 2010, it was determined that our oil and natural gas properties were not impaired.
Non-operating income and expense. The following table sets forth the components of non-operating income and expense for the periods presented:

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Non-operating income (expense):			
Realized and unrealized gain (loss):			
Commodity derivative financial instruments, net	$8,800	$21,047	$11,190
Interest rate derivatives, net	(412)	(1,311)	(5,375)
Interest expense	(85,572)	(50,580)	(18,482)
Interest and other income	59	108	151
Write-off of deferred loan costs	—	(6,195)	—
Loss on disposal of assets	(52)	(40)	(30)
Non-operating expense, net	$(77,177)	$(36,971)	$(12,546)

Commodity derivative financial instruments. The realized and unrealized gains and losses on commodity derivative financial instruments for the periods presented:

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Realized gains, net	$27,025	$3,719	$22,701
Unrealized gains (losses)	(18,225)	17,328	(11,511)
Total commodity derivative gain, net	$8,800	$21,047	$11,190

Realized gains on commodity derivative financial instruments increased by approximately $23.3 million for the year ended December 31, 2012 compared to 2011 and decreased by $19.0 million for the year ended December 31, 2011 compared to 2010, based on the cash settlement prices of our commodity derivative contracts compared to the prices specified in those contracts.

The unrealized gains on commodity derivative financial instruments experienced during the year ended December 31, 2011 converted to unrealized losses for the year ended December 31, 2012 as a result of the changing relationships between our contract prices and the associated forward curves used to calculate the fair value of our commodity derivative financial instruments in relation to expected market prices. In general, we experience unrealized gains during periods of decreasing market prices and unrealized losses during periods of increasing market prices. Additionally, at December 31, 2012, we had 27 commodity derivatives contracts with associated deferred premiums totaling approximately $25.5 million. The estimated fair value of our total deferred premiums was approximately $24.7 million at December 31, 2012 compared to $18.9 million at December 31, 2011 and $12.5 million at December 31, 2010. The fair market value of these premiums is netted against the fair market value of the underlying commodity derivative financial instruments at each period end and contributed the majority of our overall unrealized loss positions for the year ended December 31, 2012.

See Notes B.5, F and G to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding our commodity derivative financial instruments.

Interest expense and realized and unrealized gains and losses on interest rate swaps. Interest expense increased by approximately $35.0 million, or 69%, for the year ended December 31, 2012 compared to 2011, and $32.1 million, or 174%, for the year ended December 31, 2011 compared to 2010. These increases are largely due to the issuance of (i) $200.0 million in 9 1/2% senior unsecured notes due 2019 in October of 2011 in addition to the previously outstanding $350.0 million 9 1/2% senior unsecured notes due in 2019, and (ii) $500.0 million in 7 3/8% senior unsecured notes due 2022 in April of 2012.

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

(in thousands)	Year ended December 31, 2012 compared to 2011	Year ended December 31, 2011 compared to 2010
Changes in interest expense:		
Senior secured credit facility, net of capitalized interest	$(3,497)	$940
2019 senior unsecured notes	16,661	35,388
2022 senior unsecured notes	24,686	—
Term loan(1)	—	(4,574)
Broad Oak credit facility(2)	(4,928)	(1,642)
Amortization of debt issuance costs	1,327	1,505
Other	743	481
Total change in interest expense	$34,992	$32,098

(1) The term loan was entered into on July 7, 2010 and was paid in full and terminated on January 20, 2011.

(2) The Broad Oak credit facility was paid-in-full and terminated on July 1, 2011 in connection with the Broad Oak acquisition.

We have entered into certain variable-to-fixed interest rate derivatives that hedge our exposure to interest rate variations on our variable interest rate debt. At December 31, 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% and terms expiring through September 2013. At December 31, 2011, we had interest rate swaps and one interest rate cap outstanding for a notional amount of $260.0 million with fixed pay rates ranging from 1.11% to 3.41% and terms expiring through September 2013.

The table below shows our realized and unrealized losses related to interest rate swaps for the periods presented:

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Realized losses, net	$(2,115)	$(4,873)	$(5,238)
Unrealized gains (losses)	1,703	3,562	(137)
Total losses, net	$(412)	$(1,311)	$(5,375)

Write-off of deferred loan costs. In January 2011, we used a portion of the net proceeds from the issuance of our senior unsecured notes to pay in full and retire our term loan. Additionally, concurrent with the issuance of our senior unsecured notes, the borrowing base on our senior secured credit facility was lowered from $220.0 million to $200.0 million. As a result, we took a charge to expense for the debt issuance costs attributable to our term loan and a proportionate percentage of the costs incurred for our senior secured credit facility, which totaled $2.9 million and $0.3 million, respectively. As of December 31, 2012, the borrowing base on our senior secured credit facility is $825.0 million. On July 1, 2011, in conjunction with the Broad Oak acquisition, the Broad Oak credit facility was paid in full and terminated and the related debt issuance costs of $2.9 million were charged to expense.

Income tax expense. We recorded a deferred income tax expense of $32.9 million, a deferred income tax expense of $59.4 million and a deferred income tax benefit of $25.8 million for the years ended December 31, 2012, 2011 and 2010, respectively, due to fluctuations in income before income taxes as shown in the table below.

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Income before income taxes	$94,603	$164,928	$60,436
Income tax (expense) benefit	(32,949)	(59,374)	25,812
Net income	$61,654	$105,554	$86,248
Effective tax rate	35%	36%	(43)%

During the first nine months of 2010, Broad Oak had a valuation allowance against its net deferred federal tax asset which decreased our deferred income tax expense for the year ended December 31, 2010. Our effective tax rate is based on our estimated annual permanent tax differences and estimated annual pre-tax book income. Our estimates involve assumptions we believe to be reasonable at the time of the estimation.

Liquidity and capital resources

Since our IPO, our primary sources of liquidity have been borrowings under our senior secured credit facility, proceeds from our senior unsecured notes offerings, proceeds from our IPO and cash flows from operations. As we pursue reserves and production growth, we continually consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us. We believe that we have sufficient liquidity available to us from cash flow from operations and on our senior secured credit facility for our planned exploration and development activities. In addition, our hedge positions currently provide relative certainty on a majority of our cash flows from operations through 2015 even with the general decline in the prices of natural gas.

At December 31, 2012, we had $165.0 million in debt outstanding under our senior secured credit facility and $1.1 billion in senior unsecured notes, excluding the premium of $2.0 million received on the October 2011 offering of our 2019 senior unsecured notes. Additionally, we had approximately $660.0 million available for borrowings under our senior secured credit facility at December 31, 2012. We believe such availability as well as cash flows from operations and cash on hand provide us with the ability to implement our planned exploration and development activities.

As of March 8, 2013 we had $300.0 million in debt outstanding and $525.0 million available for borrowings under our senior secured credit facility.

We expect, in the future, our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite possible 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 for the periods presented are as follows:

(in thousands)	For the years ended December 31, 2012	2011	2010
Net cash provided by operating activities	$376,776	$344,076	$157,043
Net cash used in investing activities	(940,751)	(706,787)	(460,547)
Net cash provided by financing activities	569,197	359,478	319,752
Net increase (decrease) in cash	$5,222	$(3,233)	$16,248

Cash flows provided by operating activities

Net cash provided by operating activities was $376.8 million, $344.1 million and $157.0 million for the years ended December 31, 2012, 2011 and 2010, respectively. The increases of $32.7 million from 2011 to 2012 and $187.0 million from 2010 to 2011 were largely due to significant increases in revenue due to production growth driven by our successful drilling program, as well as an increase in the market price for oil in 2011 as compared to 2010.

Our operating cash flows are sensitive to a number of variables, the most significant of which are production levels and the variability of oil and natural gas prices. 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

We had cash flows used in investing activities of approximately $940.8 million, $706.8 million and $460.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. The increases of $234.0 million from 2011 to 2012 and $246.2 million from 2010 to 2011 are due to increasing our drilling efforts in our Permian Basin and Anadarko Granite Wash areas in order to take advantage of strategic vertical and horizontal drilling opportunities and the increased stabilization of oil prices.

Our cash used in investing activities for acquisitions and capital expenditures for the periods presented is summarized in the table below.

(in thousands)	For the years ended December 31, 2012	2011	2010
Acquisitions	$(20,496)	$—	$—
Capital expenditures:			
oil and natural gas properties	(895,312)	(687,062)	(454,161)
Pipeline and gathering assets	(16,241)	(13,368)	(4,277)
Other fixed assets	(8,755)	(6,413)	(2,198)
Proceeds from other asset disposals	53	56	89
Net cash used in investing activities	$(940,751)	$(706,787)	$(460,547)

Capital expenditure budget

Our board of directors approved a budget of $725 million for calendar year 2013, 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. We may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We consistently monitor and adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Cash flows provided by financing activities

We had cash flows provided by financing activities of $569.2 million, $359.5 million and $319.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Net cash provided by financing activities was primarily the result of $500.0 million in gross proceeds from the issuance of our 2022 senior unsecured notes on April 27, 2012 and net borrowings on our senior secured credit facility offset by payments of $10.8 million for loan costs.

For the year ended December 31, 2011, net cash provided by financing activities was primarily the result of $552.0 million in gross proceeds from the issuance of our 2019 senior unsecured notes of $350.0 million on January 20, 2011 and $202.0 million on October 11, 2011, net proceeds from our IPO of $319.4 million, net reductions of our senior secured credit facility and former Broad Oak credit facility totaling $306.6 million, the payment of $100.0 million to pay in full and terminate our term loan and payments of $23.2 million for loan costs. Additionally, we incurred approximately $82.0 million in debt to facilitate the Broad Oak acquisition.

For the year ended December 31, 2010, net cash from financing activities was the result of capital contributions from Warburg Pincus, certain members of our management and our independent directors totaling $85.0 million, net borrowings on our senior secured credit facility and former Broad Oak credit facility totaling $144.5 million and borrowings on our term loan of $100.0 million, all of which were offset by payments of $9.2 million for loan costs. Following the Corporate Reorganization, we no longer have any commitments from Warburg Pincus or others to contribute any capital to us.

Debt

At December 31, 2012, we were a party only to our senior secured credit facility and the indentures governing our 2019 and 2022 senior unsecured notes. The Broad Oak credit facility was terminated on July 1, 2011 in conjunction with the Broad Oak acquisition. Our term loan facility was paid in full and retired in conjunction with the closing of the January 2011 offering of our 2019 senior unsecured notes.

Senior secured credit facility. Laredo Petroleum, Inc. is the borrower on our senior secured credit facility, which has a capacity of up to $2.0 billion and will mature on July 1, 2016. On November 7, 2012, we entered into the fifth amendment to our senior secured credit facility, which increased the borrowing base to $825.0 million.

Principal amounts borrowed under the 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 ("LIBOR"), in each case, plus an applicable margin based on the ratio of outstanding senior secured credit to the borrowing base. At December 31, 2012, the applicable margin rates were 0.75% for the adjusted base rate advances and 1.75% for the Eurodollar advances. The amount of the senior secured credit facility outstanding at December 31, 2012 was subject to an interest rate of approximately 2.00%. We are also required to pay an annual commitment fee on the unused portion of the bank's commitment of 0.5%.

As of December 31, 2012, 2011 and 2010, borrowings outstanding under our senior secured credit facility totaled $165.0 million, $85.0 million and $177.5 million, respectively. As of March 8, 2013, the outstanding balance under our senior secured credit facility was $300.0 million.

Our senior secured credit facility is secured by a first priority lien on our assets (including stock of Laredo Petroleum, Inc.), including oil and natural gas properties constituting at least 80% of the present value of our proved reserves owned now or in the future. At December 31, 2012, we were subject to the following financial and non-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, depreciation, depletion, 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 both financial and non-financial covenants. We were in compliance with these covenants at December 31, 2012, 2011 and 2010.
Our senior secured credit facility contains various 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 which 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, 2012, 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, 2012, each of the following will 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 the 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 subsidiaries 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 which 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 the 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 at December 31, 2012.

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Termination of the Broad Oak credit facility. At June 30, 2011, Broad Oak had a $600.0 million revolving credit facility under its seventh amendment executed on February 1, 2011 between Broad Oak and certain financial institutions. Under the seventh amendment, the borrowing base was redetermined at $375.0 million. As defined in the Broad Oak credit facility, the Adjusted Base Rate Advances and Eurodollar Advances under the facilities bore interest payable quarterly at an Adjusted Base Rate or Adjusted LIBOR plus an applicable margin based on the ratio of outstanding revolving credit to the conforming borrowing base. At June 30, 2011, the applicable margin rates were 1.50% for the Adjusted Base Rate advances and 2.50% for the Eurodollar advances. Additionally, Broad Oak was also required to pay a quarterly commitment fee of 0.5% on the unused portion of the bank's commitment. The Broad Oak credit facility was secured by a first priority lien on Broad Oak's oil and natural gas properties. Concurrently with the Broad Oak acquisition on July 1, 2011, the Broad Oak credit facility was paid in full and terminated.

As of December 31, 2010, borrowings outstanding under the Broad Oak credit facility totaled approximately $214.1 million.

Senior unsecured notes. On January 20, 2011 and October 19, 2011, Laredo Petroleum, Inc. completed the offerings of $350.0 million principal amount and $200.0 million principal amount, respectively, 9 1/2% senior unsecured notes due 2019. The 2019 senior unsecured 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 senior unsecured notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Petroleum Holdings, Inc. and its subsidiaries (other than Laredo Petroleum, Inc.) (collectively, the “guarantors”). Our 2019 senior unsecured notes were issued under and are governed by an indenture dated January 20, 2011, among Laredo Petroleum, Inc., Wells Fargo Bank, National Association, as trustee, and the guarantors (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 senior unsecured notes may be accelerated in certain circumstances upon an event of default as set forth in the 2011 indenture.

In connection with the issuance of the 2019 senior unsecured notes, Laredo Petroleum, Inc. and the guarantors party thereto entered into registration rights agreements with the initial purchasers of the 2019 senior unsecured notes and agreed to file with the SEC a registration statement with respect to an offer to exchange the 2019 senior unsecured notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) that are registered under the Securities Act. The offer to exchange the 2019 senior unsecured notes for substantially identical notes registered under the Securities Act was consummated on January 13, 2012.

On April 27, 2012, Laredo Petroleum, Inc. completed an offering of $500.0 million aggregate principal amount of 7 3/8% senior unsecured notes due 2022. The 2022 senior unsecured 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 2022 senior unsecured notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Petroleum Holdings, Inc. and the guarantors. Our 2022 senior unsecured notes were issued under and are governed by an indenture and supplement thereto, each dated April 27, 2012 (collectively, the “2012 indenture”), among Laredo Petroleum, Inc., Wells Fargo Bank, National Association, as trustee, and the guarantors. 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 2022 senior unsecured notes may be accelerated in certain circumstances upon an event of default as set forth in the 2012 indenture. The net proceeds from the 2022 senior unsecured notes were used (i) to pay in full $280.0 million outstanding under our senior secured credit facility, and (ii) for general working capital purposes.

In connection with the issuance of the 2022 senior unsecured notes, Laredo Petroleum, Inc. and the guarantors party thereto entered into registration rights agreements with the initial purchasers of the 2022 senior unsecured notes and agreed to file with the SEC a registration statement with respect to an offer to exchange the 2022 senior unsecured notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) that are registered under the Securities Act. The offer to exchange the 2022 senior unsecured notes for substantially identical notes registered under the Securities Act was consummated on August 1, 2012.

Refer to Note C of our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for further discussion of the 2019 senior unsecured notes and the 2022 senior unsecured notes.
As of March 8, 2013, we had a total of $1.1 billion of senior unsecured notes outstanding.

Obligations and commitments

We had the following significant contractual obligations and commitments that will require capital resources at December 31, 2012:

(in thousands)	Payments due Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior secured credit facility[(1)]	$—	$—	$165,000	$—	$165,000
Senior unsecured notes	89,125	178,250	178,250	1,294,313	1,739,938
Drilling rig commitments[(2)]	16,816	—	—	—	16,816
Derivative financial instruments[(3)]	10,904	14,222	357	—	25,483
Asset retirement obligations[(4)]	865	2,218	1,242	17,180	21,505
Office and equipment leases[(5)]	1,675	2,786	1,305	446	6,212
Performance unit liability awards[(6)]	—	5,390	—	—	5,390
Total	$119,385	$202,866	$346,154	$1,311,939	$1,980,344

(1) Includes outstanding principal amount at December 31, 2012. 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, 2012, the principal on our senior secured credit facility is due on July 1, 2016.

(2) At December 31, 2012, we had several drilling rigs under term contracts which expire during 2013. 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 I to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional discussion of our drilling contract commitments.

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

(4) 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 B to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(5) See Note I to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for a description of lease obligations.

(6) Represents cash awards that were granted on February 3, 2012 under the 2011 Omnibus Equity Incentive Plan. The payout of the performance units is dependent upon the Company's relative Total Shareholder Return performance against a set of peers and will be paid out in 2015. See Note B to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional discussion of our performance units.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See Note B to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K 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 depreciation, depletion 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 proved reserves, in which case a gain or loss is recognized. The costs of unproved 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 proved 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

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 which 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. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations.

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 proved reserves, less any related income tax effects. For the years ended December 31, 2012, 2011 and 2010, 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 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 preceding 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. 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 the capitalized cost is depreciated on the unit of production method. The accretion expense is recorded as a component of depreciation, depletion and amortization in our consolidated statement of operations.

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

Derivative financial instruments

We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivative instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. Realized gains and realized losses from the settlement of commodity derivative instruments and unrealized gains and unrealized losses from valuation changes in the remaining unsettled commodity derivative instruments are reported under "Other Income (Expense)" in our consolidated statements of operations.

Stock-based compensation

We measure stock-based compensation expense at the grant date based on the fair value of an award and recognize the compensation expense on a straight-line basis over the service period, which is usually the vesting period. The fair value of the awards is based on the value of our common stock on the 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. As there are inherent uncertainties related to these factors 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 D of our consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional information regarding our stock-based compensation.

Performance unit compensation

For performance unit awards issued to management in 2012, 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. Due to the relatively short trading history for our stock, the volatility criteria utilized in the Monte Carlo simulation is based on the volatilities of a group of peer companies that have been determined to be most representative of our 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 consolidated statements of operations with the corresponding liability recorded in the “Other long-term liabilities” section of our consolidated balance sheet. 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 compensation may not accurately reflect the amount ultimately earned by the member of management. Refer to Note B of our consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional information regarding our performance unit awards.

Income taxes

At December 31, 2012, 2011 and 2010, we had deferred tax assets of $62.6 million, $95.6 million and $155.0 million, respectively.

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

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

- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition;
- the ability to recover our net operating loss carry-forward deferred tax assets in future years;
- the existence of significant proved oil and natural gas reserves;
- our ability to use tax planning strategies as well as 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 2012, 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 material 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, at December 31, 2012 and 2011, 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 seven to ten 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.

At December 31, 2012, we had charitable contribution carry-forwards of $0.2 million, which will begin to expire in 2013. 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 $0.07 million has been recorded against the related deferred tax asset.

Based on our analysis, we determined at December 31, 2012 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.

Recent accounting pronouncements

In December 2011, the FASB issued Accounting Standards Update ("ASU") 2011-11, Disclosures about Offsetting Assets and Liabilities, which requires disclosure of both gross information and net information about derivative instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to master netting arrangements. This information will enable users of an entity's financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments within the scope of the update.

The update is effective for annual periods beginning on or after January 1, 2013, and interim periods within those annual periods and is to be applied retrospectively for all comparative periods presented. We do not expect the adoption of this ASU to have a material effect on our 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, 2010 through the year ended December 31, 2012. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and we do experience 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” refers to the risk of loss arising from adverse changes in oil and natural gas prices and 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 derivative instruments, such as collars, swaps, puts and basis swaps 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 flow from operations due to fluctuations in commodity prices. We have not elected hedge accounting on these derivatives and, therefore, the unrealized 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 an unrealized gain or loss. During the years ended December 31, 2012, 2011 and 2010 we recognized an unrealized loss of $18.2 million, unrealized gain of $17.3 million and unrealized loss of $11.5 million, respectively, related to our commodity derivatives, based on market price fluctuations compared to prices in our commodity derivative contracts.

Our hedged positions as of December 31, 2012 are as follows:

	Year 2013	Year 2014	Year 2015	Total
Oil[(1)]				
Total volume hedged with ceiling price (Bbl)	1,368,000	726,000	252,000	2,346,000
Weighted average ceiling price ($/Bbl)	$109.28	$128.87	$135.00	$118.11
Total volume hedged with floor price (Bbl)	2,448,000	1,266,000	708,000	4,422,000
Weighted average floor price ($/Bbl)	$76.48	$75.13	$75.00	$75.86
Natural gas[(2)]				
Total volume hedged with ceiling price (MMBtu)	16,060,000	18,120,000	15,480,000	49,660,000
Weighted average ceiling price[(3)] ($/MMBtu)	$5.77	$6.09	$6.00	$5.96
Total volume hedged with floor price (MMBtu)	22,660,000	18,120,000	15,480,000	56,260,000
Weighted average floor price[(3)] ($/MMBtu)	$3.57	$3.38	$3.00	$3.35
Oil basis swaps				
Total volume hedged (Bbl)	668,000	62,000	—	730,000
Weighted average price ($/Bbl)	$2.60	$2.60	$—	$2.60
Natural gas basis swaps				
Total volume hedged[(4)] (MMBtu)	1,200,000	—	—	1,200,000
Weighted average price ($/MMBtu)	$0.33	$—	$—	$0.33

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(1) The oil derivatives are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude Oil.

(2) The natural gas derivatives are settled based on NYMEX natural gas futures, the Northern Natural Gas Co. demarcation price, the ANR Oklahoma index gas price, West Texas WAHA index gas price or the Panhandle Eastern Pipeline spot price of natural gas for the calculation period. The basis swap derivatives are settled based on the differential between the NYMEX natural gas futures and the West Texas WAHA index gas price.

(3) The cash settlement price of our basis swaps is calculated on the difference between our natural gas futures contracts that settle on the NYMEX index and the NYMEX index price at the time of settlement. At December 31, 2012, we had 20,000 MMBtu for 2013 in basis swaps that did not have corresponding volumes hedged with a NYMEX index price. As such, the weighted average price of the basis differential attributable to these volumes has not been included in the weighted average ceiling and floor prices presented above as these basis contracts are not expected to settle based on our December 31, 2012 hedge positions.

(4) Total volume hedged for natural gas basis swaps includes 20,000 MMBtu for 2013 in basis swaps that did not have corresponding volumes hedged with a NYMEX index price at December 31, 2012.

The fair values of our commodity derivatives are largely determined by estimates of the forward curves of the relevant price indices. At December 31, 2012, a 10% change in the forward curves associated with our commodity derivative instruments would have changed our net positions by the following amounts:

(in thousands)	10% Increase	10% Decrease
Commodity derivatives	$(18,546)	$25,469

Interest rate risk. Our senior secured credit facility bears interest at a floating rate, and at December 31 2012, we had approximately $165.0 million in indebtedness outstanding on our senior secured credit facility. Our 2019 and 2022 senior unsecured notes bear fixed interest rates and we had $550.0 million (excluding the remaining premium of $1.8 million) and $500.0 million outstanding, respectively, at December 31, 2012, as shown in the table below.

	Expected maturity date						
(in millions except for interest rates)	2013	2014	2015	2016	2017	Thereafter	Total
2019 senior unsecured notes - fixed rate	$—	$—	$—	$—	$—	$550.0	$550.0
Average interest rate	— %	— %	— %	— %	— %	9.5 %	9.5 %
2022 senior unsecured notes - fixed rate	$—	$—	$—	$—	$—	$500.0	$500.0
Average interest rate	— %	— %	— %	— %	— %	7.375 %	7.375 %
Senior secured credit facility - variable rate	$—	$—	$—	$165.0	$—	$—	$165.0
Average interest rate	— %	— %	— %	2.0 %	— %	— %	2.0 %

Through interest rate derivative contracts, we have attempted to mitigate our exposure to changes in interest rates. We have entered into various fixed interest rate swaps and a cap agreement which hedge our exposure to interest rate variations on our senior secured credit facility. At December 31, 2012, we had one interest rate swap and one interest rate cap outstanding for a notional amount of $100.0 million with fixed pay rates ranging from 1.11% to 3.00% and terms expiring in September 2013.

Counterparty and customer credit risk. Our principal exposures to credit risk are through receivables resulting from derivatives financial contracts (approximately $6.7 million at December 31, 2012), joint interest receivables (approximately $30.9 million at December 31, 2012) and the receivables from the sale of our oil and natural gas production (approximately $48.4 million at December 31, 2012), which we market to energy marketing companies and refineries.

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not 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 are each lenders in our senior secured credit facility. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party.

Refer to Note H of our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K or additional disclosures regarding credit risk, including from related parties.

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 at December 31, 2012 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, 2012, 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 “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 at December 31, 2012.

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 at December 31, 2012. The report, which expresses an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting at December 31, 2012, 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 Holdings, Inc.

We have audited the internal control over financial reporting of Laredo Petroleum Holdings, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2012, based on criteria established in 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, 2012, based on criteria established in 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, 2012, and our report dated March 12, 2013 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP
Tulsa, Oklahoma
March 12, 2013

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 on Form 10-K. 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, 2012.

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, 2012.

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, 2012.

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, 2012.

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, 2012.

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	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 S-1/A (File No. 333-176439) filed on November 14, 2011).
4.2	Indenture, dated as of January 20, 2011, among Laredo Petroleum, Inc., the several guarantors named therein, and Wells Fargo Bank, National Association, as trustee. (incorporated by reference to Exhibit 4.2 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
4.3	Supplemental Indenture, dated as of July 20, 2011, among Laredo Petroleum, Inc., Laredo Petroleum—Dallas, Inc., the guarantors listed on Schedule A thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
4.4	Second Supplemental Indenture, dated as of December 19, 2011, among Laredo Petroleum, Inc., Laredo Petroleum Holdings, Inc., the guarantors listed on Schedule A thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
4.5	Third Supplemental Indenture, dated as of December 19, 2011, among Laredo Petroleum, Inc., Laredo Petroleum Holdings, Inc., the guarantors listed on Schedule A thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).

4.6	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).
4.7	Supplemental 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 4.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on April 30, 2012).

Exhibit Number	Description
10.1	Third Amended and Restated Credit Agreement, dated as of July 1, 2011, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as Administrative Agent, Bank of America, N.A. and JPMorgan Chase Bank, N.A., as Co-Syndication Agents, Societe Generale, Union Bank, N.A. and BMO Harris Financing, Inc., as Co-Documentation Agents, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and the financial institutions listed on Schedule I thereto (incorporated by reference to Exhibit 10.1 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
10.2	First Amendment to Third Amended and Restated Credit Agreement, dated as of October 11, 2011, among Laredo Petroleum, Inc., each of the guarantors thereto, each of the banks signatories thereto, and Wells Fargo Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.4 of Laredo's Registration Statement on Form S-1A (File No. 333-176439) filed on November 14, 2011).
10.3	Limited Consent and Second Amendment to Third Amended and Restated Credit Agreement, dated as of November 23, 2011, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, the guarantors signatories thereto and the banks signatories thereto (incorporated by reference to Exhibit 10.3 of Laredo's Registration Statement on From S-4/A (File No. 333-173984-05) filed on December 12, 2011).
10.4	Third Amendment to Third Amended and Restated Credit Agreement, dated as of April 24, 2012, among Laredo Petroleum, Inc., each of the guarantors thereto, each of the banks signatories thereto, and Wells Fargo Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on April 25, 2012).
10.5	Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of April 27, 2012, among Laredo Petroleum, Inc., each of the guarantors thereto, each of the banks signatories thereto, and Wells Fargo Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on April 30, 2012).
10.6	Contribution Agreement, dated as of June 15, 2011, by and among Broad Oak Energy, Inc., Warburg Pincus Private Equity IX, L.P., the other persons listed as Contributors on the signature pages thereto and Laredo Petroleum, LLC (incorporated by reference to Exhibit 10.2 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
10.7	Stock Purchase and Sale Agreement, dated as of June 15, 2011, by and among Laredo Petroleum, Inc. and the individuals listed as Sellers on the signature pages thereto (incorporated by reference to Exhibit 10.3 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
10.8	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).
10.9#	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).
10.10#	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).

10.11#	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).
10.12#	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).
10.13#	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).
10.14#	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).
10.15	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).
10.16#*	Form of 2013 Performance Compensation Award Agreement.
10.17*	Non-Exclusive Aircraft Lease Agreement, dated January 1, 2013 between Lariat Ranch, LLC and Laredo Petroleum, Inc.
21.1*	List of Subsidiaries of Laredo Petroleum Holdings, Inc.

Exhibit Number	Description
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.

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* 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 HOLDINGS INC.	
Date: March 12, 2013	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 and Kenneth E. Dornblaser, 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)	March 12, 2013
/s/ RICHARD C. BUTERBAUGH Richard C. Buterbaugh	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	March 12, 2013
/s/ JERRY R. SCHUYLER Jerry R. Schuyler	Director, President and Chief Operating Officer	March 12, 2013
/s/ PETER R. KAGAN Peter R. Kagan	Director	March 12, 2013
/s/ JAMES R. LEVY James R. Levy	Director	March 12, 2013
/s/ B.Z. (BILL) PARKER B.Z. (Bill) Parker	Director	March 12, 2013
/s/ PAMELA S. PIERCE Pamela S. Pierce	Director	March 12, 2013
/s/ AMBASSADOR FRANCIS ROONEY Ambassador Francis Rooney	Director	March 12, 2013
/s/ DR. MYLES W. SCOGGINS Dr. Myles W. Scoggins	Director	March 12, 2013
/s/ EDMUND P. SEGNER, III Edmund P. Segner, III	Director	March 12, 2013
/s/ DONALD D. WOLF Donald D. Wolf	Director	March 12, 2013

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Laredo Petroleum Holdings, Inc.

We have audited the accompanying consolidated balance sheets of Laredo Petroleum Holdings, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2012 and 2011, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. 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 Holdings, Inc. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 12, 2013, expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP
Tulsa, Oklahoma
March 12, 2013

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

	December 31, 2012	2011
Assets		
Current assets:		
Cash and cash equivalents	$33,224	$28,002
Accounts receivable, net	83,840	74,135
Derivative financial instruments	4,644	13,281
Deferred income taxes	12,713	5,202
Other current assets	3,016	2,318
Total current assets	137,437	122,938
Property and equipment:		
Oil and natural gas properties, full cost method:		
Proved properties	2,993,266	2,083,015
Unproved properties not being amortized	159,946	117,195
Pipeline and gas gathering assets	74,877	58,136
Other fixed assets	25,599	16,948
	3,253,688	2,275,294
Less accumulated depreciation, depletion, amortization and impairment	1,139,797	896,785
Net property and equipment	2,113,891	1,378,509
Deferred income taxes	49,916	90,376
Derivative financial instruments	2,058	6,510
Deferred loan costs, net	29,444	23,457
Other assets, net	5,558	5,862
Total assets	$2,338,304	$1,627,652
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$48,672	$46,007
Undistributed revenue and royalties	36,065	26,844
Accrued capital expenditures	121,612	91,022
Accrued compensation and benefits	10,318	11,270
Derivative financial instruments	1,325	4,187
Accrued interest payable	26,106	20,112
Other current liabilities	17,970	14,919
Total current liabilities	262,068	214,361
Long-term debt	1,216,760	636,961
Derivative financial instruments	3,260	2,415
Asset retirement obligations	21,120	12,568
Other noncurrent liabilities	3,373	1,334
Total liabilities	1,506,581	867,639
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued at December 31, 2012 and 2011	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized, and 128,298,559 and 127,617,391 issued, net of treasury, at December 31, 2012 and 2011, respectively	1,283	1,276
Additional paid-in capital	961,424	951,375
Accumulated deficit	(130,980)	(192,634)

Treasury stock, at cost, 7,609 common shares at December 31, 2012 and 2011	(4)	(4)
Total stockholders' equity	831,723	760,013
Total liabilities and stockholders' equity	$2,338,304	$1,627,652

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

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

	For the years ended December 31,		
	2012	2011	2010
Revenues:			
Oil and natural gas sales	$583,569	$506,255	$239,783
Natural gas transportation and treating	4,511	4,015	2,217
Total revenues	588,080	510,270	242,000
Costs and expenses:			
Lease operating expenses	67,325	43,306	21,684
Production and ad valorem taxes	37,637	31,982	15,699
Natural gas transportation and treating	1,468	977	2,501
Drilling and production	2,915	3,817	340
General and administrative (including non-cash stock-based compensation of $10,056, $6,111 and $1,257 for the years ended December 31, 2012, 2011 and 2010, respectively)	62,106	51,064	30,908
Accretion of asset retirement obligations	1,200	616	475
Depreciation, depletion and amortization	243,649	176,366	97,411
Impairment expense	—	243	—
Total costs and expenses	416,300	308,371	169,018
Operating income	171,780	201,899	72,982
Non-operating income (expense):			
Realized and unrealized gain (loss):			
Commodity derivative financial instruments, net	8,800	21,047	11,190
Interest rate derivatives, net	(412)	(1,311)	(5,375)
Interest expense	(85,572)	(50,580)	(18,482)
Interest and other income	59	108	151
Write-off of deferred loan costs	—	(6,195)	—
Loss on disposal of assets	(52)	(40)	(30)
Non-operating expense, net	(77,177)	(36,971)	(12,546)
Income before income taxes	94,603	164,928	60,436
Income tax (expense) benefit:			
Deferred	(32,949)	(59,374)	25,812
Total income tax (expense) benefit	(32,949)	(59,374)	25,812
Net income	$61,654	$105,554	$86,248
Net income per common share (Note K):			
Basic	$0.49	$0.98	
Diluted	$0.48	$0.98	
Weighted average common shares outstanding (Note K):			
Basic	126,957	107,187	
Diluted	128,171	108,099	

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

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

	Series A		BOE Preferred		Restricted Units		Treasury Units	Common Stock		Additional paid-in capital	Treasury Stock (at cost)		Other equity interests
	Units	Amount	Units	Amount	Units	Amount		Shares	Amount		Shares	Amount	
Balance, December 31, 2009	95,952	$524,700	—	$—	26,959	$3,273	—	—	$—	$—	—	$—	$145,570
Issuance of equity interests	4,000	25,000	—	—	—	—	—	—	—	—	—	—	10,000
Purchase of equity interests	—	—	—	—	—	—	(513)	—	—	—	—	—	—
Cancellation of Series A Units	(82)	(513)	—	—	—	—	513	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	6,286	1,231	—	—	—	—	—	—	26
Cancellation of restricted units	—	—	—	—	(1,813)	—	—	—	—	—	—	—	—
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—
Balance, December 31, 2010	99,870	549,187	—	—	31,432	4,504	—	—	—	—	—	—	155,596
Purchase of equity interests	—	—	—	—	—	—	(125)	—	—	—	—	—	—
Cancellation of Series A Units	(20)	(125)	—	—	—	—	125	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	9,859	5,829	—	—	—	—	—	—	132
Purchase of restricted units	—	—	—	—	—	—	(38)	—	—	—	—	—	—
Cancellation of restricted units	—	—	—	—	(1,389)	(37)	38	—	—	—	—	—	—
Broad Oak Transaction	—	—	88,986	73,765	—	—	—	—	—	—	—	—	(155,728)
Common shares issued upon Corporate Reorganization	(99,850)	(549,062)	(88,986)	(73,765)	(39,902)	(10,296)	—	107,500	1,075	632,048	—	—	—
Common shares issued at initial public offering, net of offering costs	—	—	—	—	—	—	—	20,125	201	319,177	—	—	—
Stock-based compensation	—	—	—	—	—	—	—	—	—	150	—	—	—
	—	—	—	—	—	—	—	(8)	—	—	8	(4)	—

Shares repurchased													
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—
Balance, December 31, 2011	—	—	—	—	—	—	—	127,617	1,276	951,375	8	(4)	—
Restricted stock awards	—	—	—	—	—	—	—	932	9	(9)	—	—	—
Restricted stock forfeitures	—	—	—	—	—	—	—	(251)	(2)	2	—	—	—
Stock-based compensation	—	—	—	—	—	—	—	—	—	10,056	—	—	—
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—
Balance, December 31, 2012	—	$—	—	$—	—	$—	—	128,298	$1,283	$961,424	8	$(4)	$—

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

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

	For the years ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income	$61,654	$105,554	$86,248
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax expense (benefit)	32,949	59,374	(25,812)
Depreciation, depletion and amortization	243,649	176,366	97,411
Impairment expense	—	243	—
Non-cash stock-based compensation	10,056	6,111	1,257
Accretion of asset retirement obligations	1,200	616	475
Unrealized loss (gain) on derivative financial instruments, net	16,522	(20,890)	11,648
Premiums paid for derivative financial instruments	(6,118)	(555)	(5,397)
Amortization of premiums paid for derivative financial instruments	668	471	155
Amortization of deferred loan costs	4,816	3,871	2,132
Write-off of deferred loan costs	—	6,195	—
Amortization of October 2011 Notes premium	(202)	(39)	—
Amortization of other assets	19	19	19
Loss on disposal of assets	52	40	30
(Increase) decrease in accounts receivable	(9,705)	(30,196)	(23,299)
(Increase) decrease in other current assets	(414)	(833)	(2,331)
Increase (decrease) in accounts payable	2,665	(3,825)	5,711
Increase (decrease) in undistributed revenues and royalties	9,221	16,180	735
Increase (decrease) in accrued compensation and benefits	(952)	2,492	5,621
Increase (decrease) in other accrued liabilities	8,801	23,031	2,457
Increase (decrease) in other noncurrent liabilities	98	(149)	(17)
Increase (decrease) in fair value of performance unit awards	1,797	—	—
Net cash provided by operating activities	376,776	344,076	157,043
Cash flows from investing activities:			
Capital expenditures:			
Acquisitions	(20,496)	—	—
Oil and natural gas properties	(895,312)	(687,062)	(454,161)
Pipeline and gas gathering assets	(16,241)	(13,368)	(4,277)
Other fixed assets	(8,755)	(6,413)	(2,198)
Proceeds from other fixed asset disposals	53	56	89
Net cash used in investing activities	(940,751)	(706,787)	(460,547)
Cash flows from financing activities:			
Broad Oak transaction	—	(81,963)	—
Borrowings on revolving credit facilities	360,000	790,100	250,300
Payments on revolving credit facilities	(280,000)	(1,096,700)	(105,800)
Borrowings on term loan	—	—	100,000
Payments on term loan	—	(100,000)	—
Issuance of 2019 Notes	—	552,000	—
Issuance of 2022 Notes	500,000	—	—
Proceeds from initial public offering, net	—	319,378	—
Proceeds from issuance of equity interests, net	—	—	10,000

Purchase of equity interests and units, net	—	(164)	(513)
Purchase of treasury stock	—	(3)	—
Capital contributions	—	—	75,000
Payments for loan costs	(10,803)	(23,170)	(9,235)
Net cash provided by financing activities	569,197	359,478	319,752
Net increase (decrease) in cash and cash equivalents	5,222	(3,233)	16,248
Cash and cash equivalents, beginning of period	28,002	31,235	14,987
Cash and cash equivalents, end of period	$33,224	$28,002	$31,235
Supplemental disclosure of cash flow information:			
Cash paid during the period:			
Interest, net of $627, zero and zero, respectively, of capitalized interest for the years ended December 31, 2012, 2011, and 2010 respectively	$74,638	$31,157	$15,223

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

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Laredo Petroleum Holdings, Inc.
Notes to the consolidated financial statements
December 31, 2012, 2011 and 2010

A—Organization
Laredo Petroleum Holdings, Inc. ("Laredo Holdings") together with its subsidiaries, is an independent energy company focused on the exploration, development and acquisition of oil and natural gas properties primarily in the Permian and Mid-Continent regions of the United States. Laredo Holdings was incorporated pursuant to the laws of the State of Delaware on August 12, 2011 for purposes of a Corporate Reorganization (as defined below) and the initial public offering of its common stock (the "IPO") on December 20, 2011. As a holding company, Laredo Holdings' management operations are conducted through its wholly-owned subsidiary, Laredo Petroleum, Inc. ("Laredo"), a Delaware corporation, and Laredo'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.
On July 1, 2011, Laredo Petroleum, LLC ("Laredo LLC"), a Delaware limited liability company, and Laredo completed the acquisition of Broad Oak Energy, Inc. ("Broad Oak"), a Delaware corporation, for a combination of equity and cash. Prior to the acquisition, Broad Oak was owned by its management and Warburg Pincus Private Equity IX, L.P. ("Warburg Pincus IX"). On July 19, 2011, Broad Oak's name was changed to Laredo Petroleum—Dallas, Inc.
On December 19, 2011, immediately prior to the IPO, Laredo LLC merged with and into Laredo Holdings, with Laredo Holdings being the surviving entity. Warburg Pincus IX and other affiliates of Warburg Pincus LLC were majority owners of Laredo LLC and are of Laredo Holdings. The preferred units and certain series of restricted units of Laredo LLC were exchanged into shares of common stock of Laredo Holdings based on the pre-offering equity value of such units (the "Corporate Reorganization"). The common stock has one vote per share and a par value of $0.01 per share.
On October 17, 2012, Laredo Holdings completed an underwritten secondary public offering of 14,375,000 shares of its common stock by affiliates of Warburg Pincus LLC, the selling stockholders, at a price of $20.25 per share, which included the additional 1,875,000 shares of common stock that were subject to the underwriters' option to purchase from the selling stockholders. The selling stockholders received all proceeds from this offering. No shares were sold by Laredo Holdings or its management. The Company incurred approximately $0.8 million in costs relating to this secondary public offering pursuant to a registration rights agreement with the selling stockholder.
In these notes, the "Company," when used in the present tense, prospectively or for historical periods since December 19, 2011, refers to Laredo Holdings, Laredo and its subsidiaries collectively, and for historical periods prior to December 19, 2011 refers to Laredo LLC, Laredo and its subsidiaries collectively, unless the context indicates otherwise.
B—Basis of presentation and significant accounting policies
1. 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 Broad Oak acquisition discussed in Note A was accounted for in a manner similar to a pooling of interests. The historical financial statements present the assets and liabilities of Laredo Holdings and subsidiaries and Broad Oak at historical carrying values and their operations as if they were consolidated for all periods presented. All material intercompany transactions and account balances have been eliminated in the consolidation of accounts. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The Company operates oil and natural gas properties as one business segment, which explores, develops and produces oil and natural gas.
2. Use of estimates in the preparation of consolidated financial statements
The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management of the Company 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 from these estimates.

Significant estimates include, but are not limited to, estimates of the Company's reserves of oil and natural gas, future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, stock-based compensation, deferred income taxes and fair values of commodity derivatives, interest rate derivatives and commodity deferred premiums. 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 are reasonable under the circumstances. As future events and their effects cannot be determined with precision, actual 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.

3. Cash and cash equivalents

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. 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.

4. 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 and oil and natural gas 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 and as the operator in the majority of its wells 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 balances over 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)	2012	2011
Oil and natural gas sales	$48,445	$49,434
Joint operations, net[1]	30,925	24,190
Other	4,470	511
Total	$83,840	$74,135

(1) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of approximately $0.1 million at each of December 31, 2012 and 2011.

5. Derivative financial instruments

The Company uses derivative financial instruments 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 to 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, the Company enters into derivative contracts in the form of interest rate derivatives to minimize the effects of fluctuations in interest rates.

Derivative instruments are recorded at fair value and are included on the consolidated balance sheets as assets or liabilities. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists. The Company determines the fair value of its derivative financial instruments utilizing pricing models for significantly 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.

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 statement of operations in the period of change. Realized and unrealized gains and losses on derivatives are included in cash flows from operating activities (see Note F).

Laredo Petroleum Holdings, Inc.
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6. Other current liabilities

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

(in thousands)	2012	2011
Lease operating expense payable	$9,766	$5,297
Prepaid drilling liability	2,916	2,378
Production taxes payable	2,121	1,493
Current portion of asset retirement obligations	385	506
Other accrued liabilities	2,782	5,245
Total other current liabilities	$17,970	$14,919

7. 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 $159.9 million and $117.2 million of such costs were excluded from the amortization base at December 31, 2012 and 2011, 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 $1.1 billion and $884.5 million for the years ended December 31, 2012 and 2011, respectively. Depletion expense for oil and natural gas properties was $237.1 million, $171.5 million and $93.8 million for the years ended December 31, 2012, 2011 and 2010, respectively. There were no impairments recorded for the years ended December 31, 2012, 2011 and 2010. Depletion per barrel of oil equivalent for the Company's oil and natural gas properties was $20.98, $19.82 and $18.00 for the years ended December 31, 2012, 2011 and 2010, respectively.

The Company excludes the costs directly associated with acquisition and evaluation of unproved properties from the depletion calculation until it is determined whether or not proved reserves can be assigned to the 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 proved reserves, and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

The full cost ceiling is based principally on the estimated future net cash flows from 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 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.

At 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 oil and natural gas properties did not exceed the full cost ceiling amount at December 31, 2012. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company's actual full cost ceiling test calculation and impairment analyses in future periods.

At December 31, 2011, 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, 2011 of $3.99 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, 2011 of $92.71 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 oil and natural gas properties did not exceed the full cost ceiling amount at December 31, 2011.

At December 31, 2010, 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, 2010 of $4.15 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, 2010 of $75.96 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 oil and natural gas properties did not exceed the full cost ceiling amount at December 31, 2010.

8. Pipeline and gas gathering assets

Pipeline and gas gathering assets are recorded at cost, net of accumulated depletion, depreciation and amortization ("DD&A"), and consist of gathering assets and related equipment. Depreciation of assets is provided using the shorter of the lease term or the straight-line method based on estimated useful lives of twenty years, as applicable. Expenditures for major renewals or betterments, 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. DD&A expense for pipeline and gathering assets was $3.2 million, $2.5 million and $2.0 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Pipeline and gathering assets consist of the following as of December 31:

(in thousands)	2012	2011
Pipeline and gas gathering assets	$74,877	$58,136
Less accumulated depreciation and amortization	9,585	6,394
Total, net	$65,292	$51,742

9. Other fixed assets

Other fixed assets are recorded at cost, net of accumulated depreciation and amortization, and consist of land, furniture and fixtures, vehicles, leasehold improvements and computer hardware and software. Land is recorded at cost and is not subject to depreciation. Depreciation of other fixed assets is provided using the shorter of the lease term or 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 major renewals or betterments, 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. DD&A expense for other fixed assets was $3.3 million, $2.4 million and $1.6 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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

(in thousands)	2012	2011
Computer hardware and software	$7,774	$6,206
Leasehold improvements	3,121	1,847
Drilling service assets	7,223	5,742
Vehicles	3,396	1,279
Furniture and fixtures	1,057	1,021
Production equipment	262	255
Other	675	598
Depreciable total	23,508	16,948
Less accumulated depreciation and amortization	8,938	5,858
Depreciable total, net	14,570	11,090
Land	2,091	—
Total, net	$16,661	$11,090

10. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, 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. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits 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 at December 31, 2012 or 2011.

11. Deferred loan costs

Loan origination fees are stated at cost, net of amortization, which are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. The Company capitalized $10.8 million and $23.2 million of deferred loan costs in 2012 and 2011, respectively. The Company had total deferred loan costs of $29.4 million and $23.5 million, net of accumulated amortization of $9.2 million and $4.4 million, as of December 31, 2012 and 2011, respectively.

During the year ended December 31, 2011, the Company wrote-off $6.2 million in deferred loan costs as a result of the retirement of debt and changes in the borrowing base of the Senior Secured Credit Facility (as defined in Note C). No deferred loan costs were written off in the years ended December 31, 2012 or 2010.

Future amortization expense of deferred loan costs at December 31, 2012 is as follows:

(in thousands)	
2013	$5,197
2014	5,253
2015	5,314
2016	4,013
Thereafter	9,667
Total	$29,444

12. 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 the depletion of the asset. Changes in the liability due to the passage of time are recognized

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as an increase in the carrying amount of the liability and as corresponding accretion expense. See Note G for fair value disclosures related to the Company's asset retirement obligations.

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 obligations liability as of December 31:

(in thousands)	2012	2011
Liability at beginning of year	$13,074	$8,278
Liabilities added due to acquisitions, drilling, and other	4,233	1,519
Accretion expense	1,200	616
Liabilities settled upon plugging and abandonment	(148)	(340)
Revision of estimates	3,146	3,001
Liability at end of year	$21,505	$13,074

13. 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 liabilities approximate their fair values. See Note C for fair value disclosures related to the Company's debt obligations. The Company carries its derivative financial instruments at fair value. See Note F and Note G for details about the fair value of the Company's derivative financial instruments.

14. Treasury stock

The Company accounts for treasury stock at cost.

15. 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. 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 gas imbalance as a liability. If the underproduced working interest owner determines that an overproduced owner's share of remaining net reserves is insufficient to settle the imbalance, the underproduced owner recognizes a receivable, net of any allowance from the overproduced working interest owner.

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The following tables reflect the Company's natural gas imbalance positions as of December 31:

(dollars in thousands)	2012	2011
Natural gas imbalance current receivable (included in "Accounts receivable—Oil and natural gas sales")	$416	$22
Underproduced positions (Mcf)	176,454	6,312
Natural gas imbalance current liability (included in "Other current liabilities")	$26	$32
Overproduced positions (Mcf)	11,113	9,049
Natural gas imbalance long-term liability (included in "Other noncurrent liabilities")	$1,040	$935
Overproduced positions (Mcf)	440,478	264,808

	For the years ended December 31,		
(dollars in thousands)	2012	2011	2010
Value of net underproduced (overproduced) positions arising during the period increasing (decreasing) oil and natural gas sales	$295	$(10)	$25
Net overproduced (underproduced) positions arising during the period (Mcf)	7,592	32,353	(12,772)

16. 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)	2012	2011	2010
Fees received for the operation of jointly-owned oil and natural gas properties	$2,335	$2,241	$1,497

17. Compensation awards

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

For performance unit awards issued to management with a combination of market and service vesting criteria, a Monte Carlo simulation prepared by an independent third party is utilized in order 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. Due to the relatively short trading history for the Company's stock, the volatility criteria utilized in the Monte Carlo simulation is based on the 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 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.

On February 3, 2012, the Company awarded 49,244 performance units under the LTIP (as defined in Note D). Subsequent to the award of these performance units, 2,116 were forfeited during 2012. These performance units issued have a performance period of January 1, 2012 to December 31, 2014 and are expected to be paid in 2015 if the performance criteria is met. There were no performance unit awards issued or outstanding during the year ended December 31, 2011. Compensation expense for these awards amounted to $1.8 million for the year ended December 31, 2012, and is recognized in "General and administrative" in the Company's consolidated statements of operations and the corresponding liability is included in "Other noncurrent liabilities" in the December 31, 2012 consolidated balance sheet. The payout of these awards, if at all, will be in 2015. As there are inherent uncertainties related to the 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. Significant inputs to the Monte Carlo simulation include a volatility of 45.82%, a dividend yield of 0.00% and a risk free rate of 0.25%. The fair value of these performance awards was $5.4 million at December 31, 2012.

18. 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. 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. Additionally, the Company has not recorded any reserves for uncertain tax positions. See Note E for detail of amounts recorded in the consolidated financial statements.

19. Impairment of long-lived assets

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. During the year ended December 31, 2011, the Company reduced materials and supplies by approximately $0.2 million in order to reflect the balance at the lower of cost or market. The Company determined a lower of cost or market adjustment was not necessary for materials and supplies at December 31, 2012 and 2010. For the years ended December 31, 2012, 2011 and 2010, the Company did not record any additional impairment to property and equipment used in operations or other long-lived assets.

20. Business combinations

The Company accounts for business combinations 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 proved and unproved 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 risking factors. To compensate for the inherent risk of estimating the value of the unproved properties, the discounted future net revenues of probable and possible reserves are reduced by additional risk-weighting factors.

On July 12, 2012, the Company completed the acquisition of additional working interest in certain oil and natural gas properties located in Glasscock County, TX for a contract price of $20.5 million from a private company, subject to certain purchase price adjustments. The results of operations prior to July 2012 do not include results from this acquisition.

The following table reflects the estimated fair value of the acquired assets and liabilities associated with this acquisition at July 12, 2012:

(in thousands)	
Fair value of net assets:	
Proved oil and natural gas properties	$16,925
Unproved oil and natural gas properties	3,693
Total assets acquired	20,618
Liabilities assumed	122

Net assets acquired	$20,496
Fair value of consideration paid for net assets:	
Cash consideration	$20,496

C—Debt

1. 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)	2012	2011	2010
Cash payments for interest	$75,265	$31,157	$15,223
Amortization of deferred loan costs and other adjustments	4,940	4,231	2,256
Accrued interest related to the October 2011 Notes[(1)]	—	(3,378)	—
Change in accrued interest	5,994	18,570	1,003
Interest charges incurred	86,199	50,580	18,482
Less capitalized interest	(627)	—	—
Total interest expense	$85,572	$50,580	$18,482

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(1) As part of the October 19, 2011 offering of $200.0 million additional senior unsecured notes (further explained below), Laredo received $3.4 million in interest from the initial notes purchasers, which represents the interest on such notes that accrued from August 15, 2011 to October 19, 2011, the date of the issuance of the notes. This accrued interest was paid to the holders of such notes by Laredo on February 15, 2012.

2. 2022 Notes

On April 27, 2012, Laredo completed an offering of $500.0 million in aggregate principal amount of 7 3/8% senior unsecured notes due 2022 (the "2022 Notes"). The 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 2022 Notes are fully and unconditionally guaranteed, jointly and severally on a senior unsecured basis by Laredo Holdings and its subsidiaries, with the exception of Laredo (collectively, the "Guarantors"). The net proceeds from the 2022 Notes were used to pay in full $280.0 million outstanding under Laredo's revolving Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility") and for general working capital purposes.

The 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, Wells Fargo Bank, National Association, as trustee, and the Guarantors. 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 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 2022 Notes, in whole or in part, at any time on or after May 1, 2017, at the redemption prices (expressed as percentages of principal amount) of 103.688% for the 12-month period beginning on May 1, 2017, 102.458% for the 12-month period beginning on May 1, 2018, 101.229% for the 12-month period beginning on May 1, 2019 and 100.000% beginning on May 1, 2020 and at any time thereafter, together with any accrued and unpaid interest to, but not including, the date of redemption. In addition, before May 1, 2017, Laredo may redeem all or any part of the 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 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 2022 Notes, plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the 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 2022 Notes upon a change of control triggering event. In addition, if a change of control occurs prior to May 1, 2013, Laredo may redeem all, but not less than all, of the notes at a redemption price equal to 110% of the principal amount of the 2022 Notes redeemed, plus any accrued and unpaid interest, if any, up to the date of redemption.

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In connection with the issuance of the 2022 Notes, Laredo and the Guarantors entered into a registration rights agreement with the initial purchasers of the 2022 Notes on April 27, 2012, pursuant to which Laredo and the Guarantors filed with the SEC, a registration statement that became effective with respect to an offer to exchange the 2022 Notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) that are registered under the Securities Act of 1933, as amended (the "Securities Act"). The offer to exchange the 2022 Notes for substantially identical notes registered under the Securities Act commenced on July 2, 2012 and was consummated on August 1, 2012 with all notes exchanged.

3. 2019 Notes

On January 20, 2011, Laredo completed an offering of $350.0 million 9 1/2% Senior Notes due 2019 (the "January Notes") and on October 19, 2011, Laredo completed an offering of an additional $200.0 million 9 1/2% Senior Notes due 2019 (the "October 2011 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 9.5% 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 the Guarantors.

In connection with the issuance of the 2019 Notes, Laredo and the Guarantors entered into registration rights agreements with the initial purchasers of the 2019 Notes, pursuant to which Laredo and the Guarantors filed with the SEC a registration statement that became effective with respect to an offer to exchange the 2019 Notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) registered under the Securities Act. The offer to exchange the 2019 Notes for substantially identical notes registered under the Securities Act was consummated on January 13, 2012 with all notes exchanged.

4. Senior secured credit facility

The Senior Secured Credit Facility, which matures July 1, 2016, has a capacity of $2.0 billion, with a borrowing base of $825.0 million, at December 31, 2012. At December 31, 2012, $165.0 million was outstanding, which was subject to an interest rate of 2.0%. 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 and (ii) the Eurodollar advances under the facility bear interest, at our election, at the end of one-month, two-month, three-month, six-month or, to the extent available, 12-month interest periods (and in the case of six-month and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, based on the ratio of outstanding revolving credit to the conforming base rate. 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 conforming base rate.

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 proved 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 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) depreciation, depletion and amortization expense; (iv) exploration expenses; and (v) other non-cash charges, and (b) minus all non-cash income ("EBITDAX"), as defined in the Senior Secured Credit Facility, to 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 at December 31, 2012 and 2011.

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.

Subsequent to December 31, 2012, the Company borrowed additional funds on the Senior Secured Credit Facility. See Note N.1 for additional information.

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5. Fair value of debt

The following table presents the carrying amount and fair value of the Company's debt instruments at December 31:

(in thousands)	December 31, 2012 Carrying value	Fair value	December 31, 2011 Carrying value	Fair value
2019 Notes[1]	$551,760	$616,000	$551,961	$585,750
2022 Notes	500,000	541,250	—	—
Senior Secured Credit Facility	165,000	165,098	85,000	84,893
Total value of debt	$1,216,760	$1,322,348	$636,961	$670,643

(1) The carrying value of the 2019 Notes includes the October 2011 Notes unamortized bond premium of approximately $1.8 million and $2.0 million as of December 31, 2012 and 2011, respectively.

At December 31, 2012 and 2011, the fair value of the debt outstanding on the 2019 Notes and the 2022 Notes was determined using the December 31, 2012 and 2011 quoted market price (Level 1), respectively, and the fair value of the outstanding debt at December 31, 2012 and 2011 on the Senior Secured Credit Facility was estimated utilizing pricing models for similar instruments (Level 2). See Note G for information about fair value hierarchy levels.

D—Stock-based compensation

In November 2011, the Board of Directors of Laredo Holdings approved 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 and other awards. The LTIP provides for the issuance of 10.0 million shares. See Note N.3 for discussion of the February 2013 issuance of restricted stock, stock option awards and other awards.

The Company recognizes the fair value of stock-based payments to employees and directors as a charge against earnings. The Company recognizes stock-based payment expense over the requisite service period. Laredo Holdings' stock-based payment awards are accounted for as equity instruments. Stock-based compensation is included in "General and administrative" in the consolidated statements of operations.

1. Restricted stock awards

All restricted stock awards are treated as issued and outstanding in the accompanying consolidated financial statements. 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. Restricted stock awards converted in the Corporate Reorganization vested 20% at the grant date and then vest 20% annually thereafter. The restricted stock awards granted under the LTIP to employees vest 33%, 33% and 34% per year beginning on the first anniversary date of the grant. Restricted stock awards granted to non-employee directors vest fully on the anniversary date of the grant.

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The following table reflects the outstanding restricted stock awards for the year ended December 31, 2012 and from the Corporate Reorganization until December 31, 2011:

(in thousands, except for grant date fair values)	Restricted stock awards	Weighted average grant date fair value
Outstanding at December 19, 2011	—	$—
Exchanged	912	1.14
Vested	(1)	1.11
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

(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.

The Company utilizes the closing stock price on the date of grant to determine the fair value of service vesting restricted stock awards. For the years ended December 31, 2012, 2011 and 2010, respectively, unrecognized stock-based compensation expense related to restricted stock awards was $17.6 million, $13.0 million and $2.1 million. That cost is expected to be recognized over a weighted average period of 2.01 years.

2. Restricted stock option awards

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

(in thousands, except for weighted average exercise price and contractual term)	Restricted stock option awards	Weighted average exercise price (per option)	Weighted average 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
Vested and exercisable at end of period	—		

The Company used the Black-Scholes option pricing model to determine the fair value of restricted stock options 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 stock-based awards requires judgment, including estimating the expected term that stock options will be outstanding prior to exercise, and the associated volatility. For the years ended December 31, 2012, unrecognized stock-based compensation expense related to restricted option awards was $4.5 million. That cost is expected to be recognized over a weighted average period of 2.61 years. No restricted stock options were outstanding in the years ended December 31, 2011 or 2010.

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The assumptions used to estimate the fair value of restricted stock options granted in the year ended December 31, 2012 are as follows:

Risk-free interest rate(1)	1.14	%
Expected option life(2)	6.25 years	
Expected volatility(3)	59.98	%
Fair value per option	$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 has no historical exercise history, expected option life assumptions were developed using the simplified method in accordance with GAAP.
(3) The Company utilized a peer historical look-back, weighted with the Company's own volatility since the IPO, 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 February 3, 2012:

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 the continuous employment of the Company through February 2, 2014. Unless sooner terminated, the option will expire if and to the extent it is not exercised within 10 years from the grant date. The unvested portion of an option will expire upon termination of employment of the optionee, and the vested portion of such option will remain exercisable for (A) one year following termination of employment by death, but not later than the option expiration or (B) 90 days following termination of employment or service without cause, but not later than the expiration of the option period. The unvested and the unexercised vested portion of the option will expire upon termination of employment for cause.

3. 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)	2012	2011	2010
Restricted stock award compensation expense	$8,496	$6,111	$1,257
Restricted stock option award compensation expense	1,560	—	—
Total stock-based compensation expense	$10,056	$6,111	$1,257

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E—Income taxes

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 margin tax. Income tax expense (benefit) for the periods presented consisted of the following:

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Current taxes:			
Federal	$—	$—	$—
State	—	—	—
Deferred taxes:			
Federal	31,336	58,727	(27,345)
State	1,613	647	1,533
Income tax expense (benefit)	$32,949	$59,374	$(25,812)

Income tax expense (benefit) differed from amounts computed by applying the federal income tax rate of 34% to pre-tax income (loss) from operations as a result of the following:

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Income tax expense computed by applying the statutory rate	$32,165	$56,076	$20,548
State income tax expense, net of federal tax benefit	102	2,530	1,118
Income from non-taxable entity	—	(30)	(48)
Non-deductible stock-based compensation	1,177	2,078	418
Change in deferred tax valuation allowance	(583)	(660)	(47,888)
Other items	88	(620)	40
Income tax expense (benefit)	$32,949	$59,374	$(25,812)

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

(in thousands)	2012	2011
Derivative financial instruments	$7,108	$3,551
Oil and natural gas properties and equipment	(173,279)	(87,138)
Net operating loss carry-forward	222,017	180,740
Accrued bonus	3,502	—
Other	3,347	(926)
	62,695	96,227
Valuation allowance	(66)	(649)
Net deferred tax asset	$62,629	$95,578

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

(in thousands)	2012	2011
Deferred tax asset	$62,629	$95,578
Deferred tax liability	—	—
Net deferred tax assets	$62,629	$95,578

The Company had federal net operating loss carry-forwards totaling approximately $632.6 million and state net operating loss carry-forwards totaling approximately $185.7 million at December 31, 2012. These carry-forwards begin expiring in 2026. The Company maintains a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. At December 31, 2012, a $0.07 million valuation allowance has been recorded against the Company's charitable contribution carry-forward. The Company believes the federal and state 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. Such consideration included cumulative earnings in recent years, 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 at December 31, 2012 and 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. The deferred tax asset at December 31, 2011 included a net operating loss for Louisiana of $0.6 million. A full valuation allowance was recorded against the entire Louisiana net operating loss. A final return was filed for Louisiana as the Company is no longer doing business in that jurisdiction. The associated net operating loss deferred tax asset was written off and the valuation allowance was reversed as of December 31, 2012.

For periods beginning prior to July 1, 2011, separate federal and state income tax returns were filed for Laredo LLC, Laredo and Broad Oak. For periods beginning on or after July 1, 2011, consolidated federal and state income tax returns were and will be filed for the Company.

The Company's income tax returns for the years 2009 through 2011 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. Additionally, the statute of limitations for examination of federal net operating loss carry-overs typically does not begin to run until the year the attribute is utilized in a tax return. In evaluating its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy in identifying uncertain tax positions and considers support for each tax position, industry standards, tax return disclosures and schedules, and the significance of each position. The Company had no material adjustments to its unrecognized tax benefits during the year ended December 31, 2012.

F—Derivative financial instruments

1. Commodity derivatives

The Company engages in derivative transactions such as collars, swaps, puts and basis swaps 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, 2012, the Company had 40 open derivative contracts with financial institutions, none of which were designated as hedges for accounting purposes, which extend from January 2013 to December 2015. The contracts are recorded at fair value on the balance sheet and any realized and unrealized gains and losses are recognized in current period earnings.

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 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. 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.

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.

Each natural gas basis swap transaction has an established fixed differential between the New York Mercantile Exchange ("NYMEX") gas futures and West Texas WAHA ("WAHA") index gas price. When the NYMEX futures settlement price less the fixed WAHA differential is greater than the actual WAHA price, the difference multiplied by the hedged contract volume is paid to the Company by the counterparty. When the difference between the NYMEX futures settlement price less the fixed WAHA differential is less than the actual WAHA price, the Company pays the counterparty an amount equal to the difference multiplied by the hedged contract volume.

Each oil basis swap transaction has an established fixed differential between the West Texas Intermediate Midland Argus ("Midland") index crude oil price and the West Texas Intermediate Argus ("WTI") index crude oil price. When the WTI price less the fixed basis differential is greater than the actual Midland price, the difference multiplied by the hedged contract volume is paid to the Company by the counterparty. When the WTI price less the fixed basis differential is less than the actual Midland price, the difference multiplied by the hedged contract volume is paid by the Company to the counterparty.

During the year ended December 31, 2012, the Company entered into additional commodity contracts to hedge a portion of its estimated future production. The following table summarizes information about these additional commodity derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Aggregate volumes	Swap price	Floor price	Ceiling price	Contract period
Oil (volumes in Bbl):					
Price collar	270,000	$—	$90.00	$126.50	April 2012 - December 2012
Price collar	240,000	$—	$90.00	$118.35	January 2013 - December 2013
Price collar	198,000	$—	$70.00	$140.00	January 2014 - December 2014
Put	360,000	$—	$75.00	$—	January 2014 - December 2014
Put	180,000	$—	$75.00	$—	January 2014 - December 2014
Price collar	252,000	$—	$75.00	$135.00	January 2015 - December 2015
Put	360,000	$—	$75.00	$—	January 2015 - December 2015
Put	96,000	$—	$75.00	$—	January 2015 - December 2015
Basis swap	730,000	$2.60	$—	$—	February 2013 - January 2014
Natural gas (volumes in MMBtu):					
Swap	700,000	$2.72	$—	$—	April 2012 - October 2012
Price collar	700,000	$—	$3.25	$3.90	April 2013 - October 2013
Price collar	8,760,000	$—	$3.00	$5.00	January 2013 - December 2013
Price collar	11,160,000	$—	$3.00	$5.50	January 2014 - December 2014
Price collar	15,480,000	$—	$3.00	$6.00	January 2015 - December 2015

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The following table summarizes open positions as of December 31, 2012, and represents, as of such date, derivatives in place through December 31, 2015, on annual production volumes:

	Year 2013	Year 2014	Year 2015
Oil Positions:			
Puts:			
Hedged volume (Bbl)	1,080,000	540,000	456,000
Weighted average price ($/Bbl)	$65.00	$75.00	$75.00
Swaps:			
Hedged volume (Bbl)	600,000	—	—
Weighted average price ($/Bbl)	$96.32	$—	$—
Collars:			
Hedged volume (Bbl)	768,000	726,000	252,000
Weighted average floor price ($/Bbl)	$79.38	$75.45	$75.00
Weighted average ceiling price ($/Bbl)	$121.67	$129.09	$135.00
Basis swaps:			
Hedged volume (MMBtu)	668,000	62,000	—
Weighted average price ($/MMBtu)	$2.60	$2.60	$—
Natural Gas Positions:			
Puts:			
Hedged volume (MMBtu)	6,600,000	—	—
Weighted average price ($/MMBtu)	$4.00	$—	$—
Collars:			
Hedged volume (MMBtu)	16,060,000	18,120,000	15,480,000
Weighted average floor price ($/MMBtu)	$3.42	$3.38	$3.00
Weighted average ceiling price ($/MMBtu)	$5.79	$6.09	$6.00
Basis swaps(1):			
Hedged volume (MMBtu)	1,200,000	—	—
Weighted average price ($/MMBtu)	$0.33	$—	$—

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(1) The cash settlement price of the Company's natural gas basis swaps is calculated on the difference between the Company's natural gas futures contracts that settle on the NYMEX index and the NYMEX index price at the time of settlement. At December 31, 2012, the Company had 20,000 MMBtu for 2013 in basis swaps that did not have corresponding volumes hedged with a NYMEX index price.

The natural gas derivatives are settled based on NYMEX gas futures, the Northern Natural Gas Co. Demarcation price or the Panhandle Eastern Pipe Line spot price of natural gas for the calculation period. The oil derivatives are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude Oil. Each natural gas basis swap transaction is settled based on the differential between the NYMEX gas futures and WAHA index gas price. Each oil basis swap transaction is settled based on the differential between the West Texas Intermediate Midland Argus crude oil price and the West Texas Intermediate Argus crude oil price.

2. Interest rate derivatives

The Company is exposed to market risk for changes in interest rates related to its Senior Secured Credit Facility. Interest rate derivative agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. If LIBOR is lower than the fixed rate in the contract, the Company is required to pay the counterparties the difference, and conversely, the counterparties are required to pay the Company if LIBOR is higher than the fixed rate in the contract. For the interest rate cap below, the Company paid a premium of $0.2 million in 2010 upon entering into the agreement. The Company did not designate the interest rate derivatives as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings.

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The following presents the settlement terms of the interest rate derivatives at December 31, 2012:

(in thousands except rate data)	Year 2013		Expiration date
Notional amount	$50,000		
Fixed rate	1.11	%	September 13, 2013
Notional amount	$50,000		
Cap rate	3.00	%	September 13, 2013
Total	$100,000		

3. Balance sheet presentation

The Company's oil and natural gas commodity derivatives and interest rate derivatives are presented on a net basis in "Derivative financial instruments" in the consolidated balance sheets.

The following summarizes the fair value of derivatives outstanding on a gross basis as of December 31:

(in thousands)	2012	2011
Assets:		
Commodity derivatives:		
Oil derivatives	$16,219	$16,026
Natural gas derivatives	17,896	34,019
Interest rate derivatives	—	11
	$34,115	$50,056
Liabilities:		
Commodity derivatives:		
Oil derivatives[1]	$21,308	$28,044
Natural gas derivatives[2]	10,413	6,832
Interest rate derivatives	277	1,991
	$31,998	$36,867

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(1) The oil derivatives fair value is presented net of deferred premium liability of $18.3 million and $13.4 million at December 31, 2012 and 2011, respectively.

(2) The natural gas derivatives fair value is presented net of deferred premium liability of $6.4 million and $5.4 million at December 31, 2012 and 2011, respectively.

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, the Company exposes itself to credit risk and market risk. 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, which creates credit risk. The Company's counterparties are participants in its Senior Secured Credit Facility which is secured by the Company's oil and natural gas reserves (as described in Note C); therefore, the Company is not required to post any collateral. The Company does not require collateral from its counterparties. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that are also lenders in the Company's Senior Secured Credit Facility and 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. In accordance with the Company's standard practice, its commodity and interest rate derivatives are subject to counterparty netting under agreements governing such derivatives and, therefore, the risk of such loss is somewhat mitigated at December 31, 2012.

4. Gain (loss) on derivatives

Gains and losses on derivatives are reported on the consolidated statements of operations in the respective "Realized and unrealized gain (loss)" amounts. Realized gains (losses) represent amounts related to the settlement of derivative instruments, and for commodity derivatives, are aligned with the underlying production. Unrealized gains (losses) represent the change in fair value of the derivative instruments and are non-cash items.

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The following represents the Company's reported gains and losses on derivative instruments for the periods presented:

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Realized gains (losses):			
Commodity derivatives	$27,025	$3,719	$22,701
Interest rate derivatives	(2,115)	(4,873)	(5,238)
	24,910	(1,154)	17,463
Unrealized gains (losses):			
Commodity derivatives	(18,225)	17,328	(11,511)
Interest rate derivatives	1,703	3,562	(137)
	(16,522)	20,890	(11,648)
Total gains (losses):			
Commodity derivatives	8,800	21,047	11,190
Interest rate derivatives	(412)	(1,311)	(5,375)
	$8,388	$19,736	$5,815

G—Fair value measurements

The Company accounts for its oil and natural gas commodity and interest rate derivatives at fair value. The fair value of derivative financial instruments 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 audited consolidated balance sheets are categorized based on the 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 asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the price risk management instrument 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 that 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 of 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 year ended December 31, 2012.

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1. Fair value measurement on a recurring basis
The following presents the Company's fair value hierarchy for assets and liabilities measured at fair value on a recurring basis at December 31, 2012 and 2011.

(in thousands)	Level 1	Level 2	Level 3	Total fair value
As of December 31, 2012:				
Commodity derivatives	$—	$27,103	$—	$27,103
Deferred premiums	—	—	(24,709)	(24,709)
Interest rate derivatives	—	(277)	—	(277)
Total	$—	$26,826	$(24,709)	$2,117

(in thousands)	Level 1	Level 2	Level 3	Total fair value
As of December 31, 2011:				
Commodity derivatives	$—	$34,037	$—	$34,037
Deferred premiums	—	—	(18,868)	(18,868)
Interest rate derivatives	—	(1,980)	—	(1,980)
Total	$—	$32,057	$(18,868)	$13,189

These items are included in "Derivative financial instruments" 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 the NYMEX natural gas and crude oil prices, appropriate risk adjusted discount rates and other relevant data. Significant Level 2 assumptions associated with the calculation of discounted cash flows used in the "mark-to-market" analysis of interest rate swaps include the interest rate curves, appropriate risk adjusted discount rates and other relevant data.

The Company's deferred premiums associated with its commodity derivative contracts are categorized in 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 2.00% to 3.56%) and then amortizing the change in net present value into 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 deal containing a deferred premium entered into; however the valuation for the deals 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 third party valuation of the deferred premiums for reasonableness.

The following table presents actual cash payments required for deferred premium contracts in place at December 31, 2012, and for the calendar years following:

(in thousands)	
2013	$10,904
2014	8,135
2015	6,087
2016	357
Total	$25,483

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A summary of the changes in assets classified as Level 3 measurements for the periods presented are as follows:

	For the year ended December 31, 2012	
(in thousands)	Derivative option contracts	Deferred premiums
Balance of Level 3 at beginning of period[1]	$—	$(18,868)
Realized and unrealized gains included in earnings	—	—
Amortization of deferred premiums	—	(668)
Total purchases and settlements:		
Purchases	—	(11,291)
Settlements	—	6,118
Balance of Level 3 at end of period	$—	$(24,709)
Change in unrealized losses attributed to earnings relating to derivatives still held at end of period	$—	$—

	For the year ended December 31, 2011	
(in thousands)	Derivative option contracts	Deferred premiums
Balance of Level 3 at beginning of period	$20,026	$(12,495)
Realized and unrealized gains (losses) included in earnings	5,323	—
Amortization of deferred premiums	—	(471)
Total purchases and settlements:		
Purchases	—	(5,988)
Settlements	—	86
Transfers out of Level 3[1][2]	(25,349)	—
Balance of Level 3 at end of period	$—	$(18,868)
Change in unrealized gains attributed to earnings relating to derivatives still held at end of period	$—	$—

(1) The Company transferred the commodity derivative option contracts out of Level 3 during the year ended December 31, 2011 due to the Company's ability to utilize transparent forward price curves and volatilities published and available through independent third party vendors. As a result, the Company transferred positions from Level 3 to Level 2 as the significant inputs used to calculate the fair value are all observable.

(2) The Company's policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that caused the transfer.

2. Fair value measurement on a nonrecurring basis

The Company accounts for additions to its asset retirement obligation (see Note B.12) and the impairment of long-lived assets (see Note B.19), if any, at fair value on a nonrecurring basis in accordance with GAAP. For purposes of fair value measurement, it was determined that the impairment of long-lived assets and the additions to the asset retirement obligation are classified as Level 3 based on the use of internally developed cash flow models. No impairments of long-lived assets were recorded in the years ended December 31, 2012 or 2010. See Note B.19 for discussion of the Company's impairment of materials and supplies in the year ended December 31, 2011.

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.

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Asset retirement obligations. The accounting policies for asset retirement obligations are discussed in Note B.12, including a reconciliation of the Company's asset retirement obligation. 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 to 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) future inflation factors; and (iv) the Company's average credit adjusted risk free rate.

Impairment of oil and natural gas properties. The accounting policies for impairment of oil and natural gas properties are discussed in Note B.19. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of proved reserves and other relevant data.

H—Credit risk

The Company's oil and natural gas sales are 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 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 derivative instruments 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 derivative instruments are subject to counterparty netting under agreements governing such derivatives and therefore, the credit risk associated with its derivative counterparties is somewhat mitigated. See Note F for additional information regarding the Company's derivative instruments.

For the year ended December 31, 2012, the Company had three customers that accounted for 34.0%, 12.3%, and 10.0% of total revenues, with the same three customers accounting for 25.7%, 13.0%, and 10.7% and another customer accounting for 13.7% of oil and natural gas sales accounts receivable as of December 31, 2012. For the year ended December 31, 2011, the Company had three customers that accounted for 36.1%, 16.2% and 12.9% of total revenues, with the same three customers accounting for 31.6%, 13.9% and 15.9% and another customer accounting for 11.0% of oil and natural gas sales accounts receivable as of December 31, 2011. For the year ended December 31, 2010, the Company had three customers that accounted for 33.1%, 19.0%, and 14.5% of total revenues, with the same three customers accounting for 41.3%, 16.2%, and 14.0% of oil and natural gas sales accounts receivable as of December 31, 2010.

For the year ended December 31, 2012, the Company had two partners whose joint operations accounts receivable accounted for 66.2% and 17.0% of the Company's total joint operations accounts receivable. For the year ended December 31, 2011, the Company had three partners whose joint operations accounts receivable accounted for 30.4%, 17.4% and 16.1% of the Company's total joint operations accounts receivable.

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 a certain bank in the Senior Secured Credit Facility bank group at December 31, 2012, which exceeded the balance insured by the FDIC in the amount of $49.3 million. Management believes that the risk of loss is mitigated by the bank's reputation and financial position.

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2. Related-party transactions

The following table summarizes the net oil and natural gas sales (oil and natural gas sales less production taxes) received from the Company's related-party and included in the consolidated statements of operation for the periods presented:

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Net oil and natural gas sales(1)	$71,916	$79,300	$35,000

The following table summarizes the amounts included in oil and natural gas sales receivable from the Company's related party in the consolidated balance sheets for the periods presented:

	December 31,	
(in thousands)	2012	2011
Oil and natural gas sales receivable(1)	$6,244	$6,845

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(1) The Company has a gas gathering and processing arrangement with affiliates of Targa Resources, Inc. ("Targa"). Warburg Pincus IX, a majority stockholder of Laredo Holdings, and other affiliates of Warburg Pincus LLC, hold investment interests in Targa. One of Laredo Holdings' directors is on the board of directors of affiliates of Targa.

I—Commitments and contingencies

1. Lease commitments

The Company leases equipment and office space under operating leases expiring on various dates through 2018. Minimum annual lease commitments at December 31, 2012, and for the calendar years following are:

(in thousands)	
2013	$1,675
2014	1,570
2015	1,216
2016	785
2017	520
Thereafter	446
Total	$6,212

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

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Rent expense	$1,339	$1,175	$946

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.

2. Litigation

The Company may be involved in legal proceedings or is 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.

3. Drilling contracts

The Company has committed to several short-term drilling contracts with various third parties in order to complete its various drilling projects. The contracts contain an early termination clause that requires the Company to pay significant

Laredo Petroleum Holdings, Inc.
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penalties to the third party should the Company cease drilling efforts. These penalties could significantly impact the Company's financial statements upon contract termination. These commitments are not recorded in the accompanying consolidated balance sheets. Future commitments as of December 31, 2012 are $16.8 million. No stacked rig fees were incurred in 2012, 2011 or 2010. Management does not anticipate canceling any drilling contracts or discontinuing drilling efforts in 2013.

4. 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 and these regulations will not have a material adverse impact on the financial position or results of operations of the Company. Because these rules and regulations are frequently amended or reinterpreted, the Company is unable to predict the future cost or impact of complying with these regulations.

J—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 tax-deferred 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 total contributions to the plan for the periods presented:

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Contributions	$1,293	$1,651	$1,201

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K—Net income per share

Basic net income per share is computed by dividing net income by the weighted average number of shares outstanding for the period. Diluted net income per share reflects the potential dilution of non-vested restricted stock awards. The effect of the Company's outstanding options to purchase 459,469 shares of common stock at $24.11 per share were excluded from the calculation of diluted net income per share because the exercise price of those options was greater than the average market 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 shares outstanding and net income per share for the periods presented:

	For the years ended December 31,	
(in thousands, except for per share data)	2012	2011
Net income (numerator):		
Net income —basic and diluted	$61,654	$105,554
Weighted average shares (denominator)[(1)]:		
Weighted average shares—basic	126,957	107,187
Non-vested restricted stock	1,214	912
Weighted average shares—diluted	128,171	108,099
Net income per share:		
Basic	$0.49	$0.98
Diluted	$0.48	$0.98

(1) For the year ended December 31, 2011, weighted average shares outstanding used in the computation of basic and diluted net income per share attributable to shareholders has been computed taking into account (1) restricted stock awards converted in the Corporate Reorganization as if the conversion occurred as of the beginning of the year and (2) the 20,125,000 shares of common stock issued by the Company in the IPO.

L—Recently issued accounting standards

In December 2011, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2011-11, Disclosures about Offsetting Assets and Liabilities, to improve reporting and transparency of offsetting (netting) assets and liabilities and the related effects on the financial statements. This ASU is effective for fiscal years and interim periods within those years beginning on or after January 1, 2013. The Company does not expect the adoption of this ASU to have a material effect on the consolidated financial statements.

M—Subsidiary guarantees

Laredo Holdings and all of Laredo's wholly-owned subsidiaries (Laredo Gas, Laredo Texas and Laredo Dallas, collectively, the "Subsidiary Guarantors") have fully and unconditionally guaranteed the 2019 Notes, the 2022 Notes and the Senior Secured Credit Facility. 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, 2012 and 2011, and condensed consolidating statements of operations and condensed consolidating statements of cash flows each for the years ended December 31, 2012, 2011 and 2010, present financial information for Laredo Holdings or Laredo LLC, as applicable, as the parent of Laredo on a stand-alone basis (carrying any investments in subsidiaries under the equity method), 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 Gas and Laredo Texas are recorded on Laredo's statements of financial position, statements of operations and statements of cash flow as they are flow-through entities for income tax purposes. Laredo and the Subsidiary

Guarantors are not restricted from making distributions.

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Condensed consolidating balance sheet
December 31, 2012

(in thousands)	Laredo Holdings	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable	$—	$59,447	$24,393	$—	$83,840
Other current assets	—	52,147	1,450	—	53,597
Total oil and natural gas properties, net	—	1,213,946	817,992	—	2,031,938
Total pipeline and gas gathering assets, net	—	—	65,292	—	65,292
Total other fixed assets, net	—	13,837	2,824	—	16,661
Investment in subsidiaries	831,641	782,635	—	(1,614,276)	—
Total other long-term assets	83	136,403	—	(49,510)	86,976
Total assets	$831,724	$2,258,415	$911,951	$(1,663,786)	$2,338,304
Accounts payable	$1	$35,948	$12,723	$—	$48,672
Other current liabilities	—	157,805	55,591	—	213,396
Other long-term liabilities	—	16,261	61,002	(49,510)	27,753
Long-term debt	—	1,216,760	—	—	1,216,760
Stockholders' equity	831,723	831,641	782,635	(1,614,276)	831,723
Total liabilities and stockholders' equity	$831,724	$2,258,415	$911,951	$(1,663,786)	$2,338,304

Condensed consolidating balance sheet
December 31, 2011

(in thousands)	Laredo Holdings	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable	$—	$53,006	$21,129	$—	$74,135
Other current assets	54,921	22,691	204	(29,013)	48,803
Total oil and natural gas properties, net	—	780,152	535,525	—	1,315,677
Total pipeline and gas gathering assets, net	—	—	51,742	—	51,742
Total other fixed assets, net	—	10,321	769	—	11,090
Investment in subsidiaries	705,093	531,568	—	(1,236,661)	—
Total other long-term assets	—	142,815	—	(16,610)	126,205
Total assets	$760,014	$1,540,553	$609,369	$(1,282,284)	$1,627,652
Accounts payable	$1	$58,730	$14,198	$(26,922)	$46,007
Other current liabilities	—	130,990	39,455	(2,091)	168,354
Other long-term liabilities	—	8,779	24,148	(16,610)	16,317
Long-term debt	—	636,961	—	—	636,961
Stockholders' equity	760,013	705,093	531,568	(1,236,661)	760,013
Total liabilities and stockholders' equity	$760,014	$1,540,553	$609,369	$(1,282,284)	$1,627,652

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

(in thousands)	Laredo Holdings	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$—	$304,572	$293,658	$(10,150)	$588,080
Total operating costs and expenses	308	266,420	159,722	(10,150)	416,300
Income (loss) from operations	(308)	38,152	133,936	—	171,780
Interest expense, net	—	(85,513)	—	—	(85,513)
Other, net	61,879	8,345	(9)	(61,879)	8,336
Income (loss) from operations before income tax	61,571	(39,016)	133,927	(61,879)	94,603
Income tax benefit (expense)	83	(3,020)	(30,012)	—	(32,949)
Net income (loss)	$61,654	$(42,036)	$103,915	$(61,879)	$61,654

Condensed consolidating statement of operations
For the year ended December 31, 2011

(in thousands)	Laredo Holdings	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$—	$237,194	$280,349	$(7,273)	$510,270
Total operating costs and expenses	8	173,638	141,998	(7,273)	308,371
Income (loss) from operations	(8)	63,556	138,351	—	201,899
Interest income (expense), net	96	(45,470)	(5,098)	—	(50,472)
Other, net	105,466	10,492	3,009	(105,466)	13,501
Income from operations before income tax	105,554	28,578	136,262	(105,466)	164,928
Income tax expense	—	(12,628)	(46,746)	—	(59,374)
Net income	$105,554	$15,950	$89,516	$(105,466)	$105,554

Condensed consolidating statement of operations
For the year ended December 31, 2010

(in thousands)	Laredo LLC	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$—	$93,580	$152,373	$(3,953)	$242,000
Total operating costs and expenses	7	91,620	81,344	(3,953)	169,018
Income (loss) from operations	(7)	1,960	71,029	—	72,982
Interest income (expense), net	150	(11,911)	(6,570)	—	(18,331)
Other, net	—	13,808	(8,023)	—	5,785
Income from operations before income tax	143	3,857	56,436	—	60,436
Income tax (expense) benefit	—	(2,234)	28,046	—	25,812
Net income	$143	$1,623	$84,482	$—	$86,248

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Notes to the consolidated financial statements
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Condensed consolidating statement of cash flows
For the year ended December 31, 2012

(in thousands)	Laredo Holdings	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$61,571	$124,322	$225,841	$(34,958)	$376,776
Net cash flows used in investing activities	(116,492)	(660,295)	(225,843)	61,879	(940,751)
Net cash flows provided by financing activities	—	569,197	—	—	569,197
Net (decrease) increase in cash and cash equivalents	(54,921)	33,224	(2)	26,921	5,222
Cash and cash equivalents at beginning of period	54,921	—	2	(26,921)	28,002
Cash and cash equivalents at end of period	$—	$33,224	$—	$—	$33,224

Condensed consolidating statement of cash flows
For the year ended December 31, 2011

(in thousands)	Laredo Holdings	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$105,643	$156,648	$200,354	$(118,569)	$344,076
Net cash flows (used in) provided by investing activities	(408,748)	(415,058)	11,465	105,554	(706,787)
Net cash flows provided by (used in) financing activities	319,374	258,410	(218,306)	—	359,478
Net increase (decrease) in cash and cash equivalents	16,269	—	(6,487)	(13,015)	(3,233)
Cash and cash equivalents at beginning of period	38,652	—	6,489	(13,906)	31,235
Cash and cash equivalents at end of period	$54,921	$—	$2	$(26,921)	$28,002

Condensed consolidating statement of cash flows
For the year ended December 31, 2010

(in thousands)	Laredo LLC	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$143	$63,887	$103,218	$(10,205)	$157,043
Net cash flows used in investing activities	(52,900)	(132,564)	(275,083)	—	(460,547)
Net cash flows provided by financing activities	74,487	68,677	176,588	—	319,752
Net increase in cash and cash equivalents	21,730	—	4,723	(10,205)	16,248
Cash and cash equivalents at beginning of period	16,922	—	1,766	(3,701)	14,987
Cash and cash equivalents at end of period	$38,652	$—	$6,489	$(13,906)	$31,235

Laredo Petroleum Holdings, Inc.
Notes to the consolidated financial statements
December 31, 2012, 2011 and 2010

N—Subsequent events

1. Additional borrowing

On January 3, February 7 and March 7, 2013, the Company borrowed $40.0 million, $65.0 million and $30 million, respectively, on the Senior Secured Credit Facility. The outstanding balance under the Senior Secured Credit Facility was approximately $300.0 million at March 8, 2013.

2. Medallion Gathering & Processing, LLC

On January 4, 2013, Laredo Gas and a private equity firm formed Medallion Gathering & Processing, LLC ("Medallion") for the purpose of developing midstream solutions and providing midstream infrastructure for the Company, its affiliates, and other third parties as necessary to bring discovered oil and natural gas to market in a merchantable state. Laredo Gas contributed approximately $0.9 million effectively acquiring 49% of Medallion ownership units and the private equity firm retained 51% of Medallion ownership units. The accounting ramifications of this transaction are preliminary and currently being evaluated by the Company.

3. Restricted stock awards and other compensation

On February 15, 2013, the Company granted 1,099,256 restricted stock awards with service vesting criteria, 1,018,849 restricted stock option awards with service vesting criteria and 58,291 performance awards with a combination of market and service vesting criteria under the LTIP and related award agreements. For stock-based compensation equity awards, compensation expense will be recognized in the Company's financial statements over the awards' vesting periods based on their grant date fair value. The Company will utilize (i) the closing stock price on the date of grant of $17.34 to determine the fair value of service vesting restricted stock awards and options and (ii) a probability analysis to determine the fair value of performance awards with a combination of market and service vesting criteria.

4. New derivative contracts

Subsequent to December 31, 2012, the Company entered into the following new commodity contracts:

	Aggregate volumes	Swap price	Floor price	Ceiling price	Contract period
Oil (volumes in Bbl):					
Swap	1,377,000	$98.10	$—	$—	March 2013 - December 2013
Basis Swap	4,026,000	$1.00	$—	$—	March 2013 - December 2014
Swap	912,500	$93.65	$—	$—	January 2014 - December 2014
Swap	365,000	$93.68	$—	$—	January 2014 - December 2014
Price collar	1,277,500	$—	$80.00	$98.50	January 2015 - December 2015
Price collar	1,281,000	$—	$80.00	$93.00	January 2016 - December 2016
Natural gas (volumes in MMBtu):					
Price collar	2,900,000	$—	$3.00	$4.00	March 2013 - December 2013

Laredo Petroleum Holdings, Inc.
Supplemental oil and natural gas disclosures
December 31, 2012, 2011 and 2010

O—Supplemental oil and natural gas disclosures

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

Costs incurred in the acquisition and development of oil and natural gas assets are presented below for the periods presented:

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Property acquisition costs:			
Proved	$16,925	$—	$—
Unproved	3,693	—	—
Exploration	93,266	62,888	87,576
Development costs(1)	839,118	660,922	414,870
Total costs incurred	$953,002	$723,810	$502,446

(1) The costs incurred for oil and natural gas development activities include $7.4 million, $4.5 million and $2.0 million, in asset retirement obligations for the years ended December 31, 2012, 2011 and 2010, respectively.

2. Capitalized oil and natural gas costs

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

	For the years ended December 31,		
(in thousands)	2012	2011	2010
Capitalized costs:			
Proved properties	$2,993,266	$2,083,015	$1,379,885
Unproved properties	159,946	117,195	96,515
	3,153,212	2,200,210	1,476,400
Less accumulated depreciation, depletion, amortization and impairment	1,121,273	884,533	713,118
Net capitalized costs	$2,031,939	$1,315,677	$763,282

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2012, by year in which such costs were incurred:

(in thousands)	2012	2011	2010	2009 and prior	Total
Unproved properties	$112,104	$17,993	$14,382	$15,467	$159,946

Unproved properties, which are not subject to amortization, are not individually significant and consist primarily of lease acquisition costs. 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.

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3. 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)	2012	2011	2010
Revenues:			
Oil and natural gas sales	$583,569	$506,255	$239,783
Production costs:			
Lease operating expenses	67,325	43,306	21,684
Production and ad valorem taxes	37,637	31,982	15,699
	104,962	75,288	37,383
Other costs:			
Depreciation, depletion, amortization	237,130	171,517	93,815
Accretion of asset retirement obligation	1,200	616	475
Income tax expense	83,686	93,180	39,223
Results of operations	$156,591	$165,654	$68,887

4. 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 at December 31, 2012, 2011 and 2010. In accordance with SEC regulations, reserves at December 31, 2012, 2011 and 2010 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. Oil volumes are expressed in MBbl and natural gas volumes are expressed in MMcf.

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

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	Year ended December 31, 2011		
(in thousands)	Gas (MMcf)	Oil (MBbl)	MBOE
Proved developed and undeveloped reserves:			
Beginning of year	550,278	44,847	136,560
Revisions of previous estimates	(47,296)	(1,124)	(9,006)
Extensions, discoveries and other additions	129,846	15,912	37,553
Purchases of reserves in place	—	—	—
Production	(31,711)	(3,368)	(8,654)
End of year	601,117	56,267	156,453
Proved developed reserves:			
Beginning of year	194,481	12,420	44,833
End of year	248,598	21,762	63,195
Proved undeveloped reserves:			
Beginning of year	355,797	32,427	91,727
End of year	352,519	34,505	93,258

	Year ended December 31, 2010		
(in thousands)	Gas (MMcf)	Oil (MBbl)	MBOE
Proved developed and undeveloped reserves:			
Beginning of year	279,549	5,928	52,519
Revisions of previous estimates	(14,619)	326	(2,110)
Extensions, discoveries and other additions	306,729	40,241	91,363
Purchases of reserves in place	—	—	—
Production	(21,381)	(1,648)	(5,212)
End of year	550,278	44,847	136,560
Proved developed reserves:			
Beginning of year	135,204	2,905	25,439
End of year	194,481	12,420	44,833
Proved undeveloped reserves:			
Beginning of year	144,345	3,023	27,080
End of year	355,797	32,427	91,727

For the year ended December 31, 2012, the Company's negative revision of 55,837 MBOE of previously 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 our reserves as of December 31, 2012 were $91.21 per barrel of oil and $2.63 per MMBtu of natural gas before price differentials.

For the year ended December 31, 2011, the Company's negative revision of 9,006 MBOE of previous estimated quantities is primarily due to the removing of uneconomic proved undeveloped locations, due to increased capital cost. Extensions, discoveries and other additions of 37,553 MBOE during the year ended December 31, 2011, consist of 14,709 MBOE primarily from the drilling of new wells during the year and 22,844 MBOE from new proved undeveloped locations

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added during the year, which increased the Company's proved reserves. The latter consists of 15,009 MBOE attributable to 155 locations in our Permian Basin play and 7,835 MBOE attributable to 47 locations in our Anadarko Granite Wash play. The oil and natural gas reference prices used in computing our reserves as of December 31, 2011 were $92.71 per barrel of oil and $3.99 per MMBtu of natural gas before price differentials.

For the year ended December 31, 2010, the Company's negative revision of 2,110 MBOE of previous estimated quantities is primarily due to uneconomic proved undeveloped locations. Extensions, discoveries and other additions of 91,363 MBOE during the year ended December 31, 2010, consist of 20,533 MBOE primarily from the drilling of new wells during the year and 70,830 MBOE from new proved undeveloped locations added during the year, which increased the Company's proved reserves, the latter of which consists of 63,444 MBOE attributable to 957 vertical locations in our Permian Basin play, 7,002 MBOE attributable to 53 vertical locations in our Anadarko Granite Wash play and 384 MBOE attributable to eight locations in other areas. The oil and natural gas reference prices used in computing our reserves as of December 31, 2010 were $75.96 per barrel of oil and $4.15 per MMBtu of natural gas before price differentials.

5. 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 unproved 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, 2012, 2011 and 2010 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 $91.21, $92.71 and $75.96 per Bbl of oil and $2.63, $3.99 and $4.15 per MMBtu for December 31, 2012, 2011 and 2010, 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)	2012	2011	2010
Future cash inflows	$11,636,926	$8,856,906	$6,597,739
Future production costs	(3,163,371)	(2,562,237)	(2,057,681)
Future development costs	(2,252,559)	(1,959,818)	(1,715,836)
Future income tax expenses	(1,433,373)	(999,185)	(602,551)
Future net cash flows	4,787,623	3,335,666	2,221,671
10% discount for estimated timing of cash flows	(2,910,167)	(1,934,807)	(1,351,689)
Standardized measure of discounted future net cash flows	$1,877,456	$1,400,859	$869,982

In the foregoing determination of future cash inflows, sales prices used for oil and natural gas for December 31, 2012, 2011 and 2010 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.

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.

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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)	2012	2011	2010
Standardized measure of discounted future net cash flows, beginning of year	$1,400,859	$869,982	$267,615
Changes in the year resulting from:			
Sales, less production costs	(478,607)	(430,967)	(202,400)
Revisions of previous quantity estimates	(631,693)	(70,021)	(15,080)
Extensions, discoveries and other additions	1,287,952	529,041	788,090
Net change in prices and production costs	194,921	566,034	214,308
Changes in estimated future development costs	(3,917)	(163,399)	(62,386)
Previously estimated development costs incurred during the period	137,510	207,818	20,082
Purchases of reserves in place	25,041	—	—
Accretion of discount	176,996	106,170	26,762
Net change in income taxes	(101,955)	(176,165)	(191,714)
Timing differences and other	(129,651)	(37,634)	24,705
Standardized measure of discounted future net cash flows, end of year	$1,877,456	$1,400,859	$869,982

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.

P—Supplemental quarterly financial data - (unaudited)

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

	Year ended December 31, 2012			
(in thousands)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$150,348	$140,624	$144,700	$152,408
Operating income	55,389	41,523	37,029	37,839
Net income (loss)	26,235	30,975	(7,384)	11,828
Net income (loss) per common share:				
Basic	$0.21	$0.24	$(0.06)	$0.09
Diluted	$0.20	$0.24	$(0.06)	$0.09

	Year ended December 31, 2011			
(in thousands)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$107,111	$131,727	$132,460	$138,972
Operating income	49,162	58,471	54,603	39,663
Net income	4,670	41,072	58,246	1,566
Pro forma net income per common share:				
Basic				$0.01
Diluted				$0.01

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