Laredo Petroleum Holdings, Inc.
Form S-1/A
October 05, 2012

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As filed with the Securities and Exchange Commission on October 5, 2012

Registration No. 333-184232

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

AMENDMENT NO. 1
TO

FORM S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

LAREDO PETROLEUM HOLDINGS, INC.

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(IRS Employer Identification No.)

15 W. Sixth Street, Suite 1800
Tulsa, Oklahoma 74119
(918) 513-4570
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Kenneth E. Dornblaser
Senior Vice President & General Counsel
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(918) 513-4570
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Approximate date of commencement of proposed sale to the public:
As soon as practicable after this registration statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. 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. (check one)

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

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

Subject to completion, dated October 5, 2012

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities, and we are not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Prospectus

12,500,000 shares

Common stock

Affiliates of Warburg Pincus LLC ("Warburg Pincus"), the selling stockholders, are offering 12,500,000 shares of Laredo Petroleum Holdings, Inc.'s common stock. We will not receive any proceeds from the sale of shares of common stock offered by the selling stockholders.

Our common stock is listed on the New York Stock Exchange (the "NYSE") under the symbol "LPI." On October 4, 2012, the last sale price of our common stock as reported on the NYSE was $21.96 per share.

Investing in our common stock involves a high degree of risk. Please read "Risk factors" beginning on page 15.

	Per share	**Total**
Public offering price	$	$
Underwriting discounts and commissions	$	$
Proceeds to selling stockholders, before expenses	$	$

The selling stockholders have granted the underwriters an option, for a period of 30 days from the date of this prospectus, to purchase up to 1,875,000 additional shares of our common stock. We will not receive any proceeds from the sale of shares of common stock to be offered by the selling stockholders.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the accuracy or adequacy of this prospectus. Any representation to the contrary is a criminal offense.

Delivery of the shares of common stock will be made on or about , 2012.

J.P. Morgan

Goldman, Sachs & Co.

BofA Merrill Lynch

Wells Fargo Securities

BMO Capital Markets	**Capital One Southcoast**
Scotiabank / Howard Weil	**SOCIETE GENERALE**
BB&T Capital Markets	**BOSC, Inc.**
Comerica Securities	**Mitsubishi UFJ Securities**

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You should rely only on the information contained in this prospectus or in any free writing prospectus we may authorize to be delivered to you. Neither we, the selling stockholders, nor the underwriters have authorized anyone to provide you with additional or different information. If anyone provides you with different or inconsistent information, you should not rely on it. The selling stockholders are offering to sell, and seeking offers to buy, our common stock only in jurisdictions where offers and sales are permitted. The information in this prospectus is accurate as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of our common stock. Our business, financial condition, results of operation and prospects may have changed since that date.

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Through and including , 2012 (25 days after the commencement of this offering), all dealers that effect transactions in our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This delivery requirement is in addition to a dealer's obligation to deliver a prospectus when acting as an underwriter and with respect to their unsold allotments or subscriptions.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. See "Risk factors" and "Forward-looking statements."

Industry and market data

This prospectus includes industry and market data that we obtained from independent industry publications, government publications or other published independent sources. These publications generally state that the information contained therein has been obtained from sources believed to be reliable, although they do not guarantee the accuracy or completeness of such information. While we believe that each of these publications is reliable, we have not independently verified any of the data from third-party sources nor have we ascertained the underlying economic or operational assumptions relied upon therein.

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Prospectus summary

This summary highlights selected information contained elsewhere in this prospectus. You should read the entire prospectus, including the information presented under the headings "Risk factors," "Forward-looking statements" and "Management's discussion and analysis of financial condition and results of operations" and the unaudited consolidated financial statements and condensed notes thereto and the audited consolidated financial statements and notes thereto included elsewhere in this prospectus before making an investment decision with respect to our common stock. Unless otherwise indicated, information presented in this prospectus assumes that the underwriters' option to purchase additional shares of common stock is not exercised. We have provided definitions for certain oil and natural gas terms used in this prospectus in the "Glossary of oil and natural gas terms" beginning on page A-1 of this prospectus.

In this prospectus, the consolidated and historical financial information, operational data and reserve information for Laredo and our acquired subsidiary Broad Oak Energy, Inc., a Delaware corporation ("Broad Oak" and subsequently renamed Laredo Petroleum Dallas, Inc.), present the assets and liabilities of Laredo Petroleum Holdings, Inc. 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.

Unless the context otherwise requires, references in this prospectus to "Laredo," "we," "our," "us" or similar terms refer to Laredo Petroleum, LLC, a Delaware limited liability company, and its subsidiaries before the completion of our corporate reorganization in December 2011, and to Laredo Petroleum Holdings, Inc., a Delaware corporation, and its subsidiaries as of the completion of our corporate reorganization and thereafter. For a description of the corporate reorganization, see " Corporate history and structure" and "Certain relationships and related party transactions Corporate reorganization."

Laredo Petroleum Holdings, Inc.

Overview

We are 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 June 30, 2012, we have assembled 188,014 net acres in the Permian Basin and 37,924 net acres in the Anadarko Granite Wash.

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 80 miles long (north/south) in Glasscock, Howard, Reagan and Sterling Counties, and is referred to in this prospectus as the "Permian-Garden City" area. As of June 30, 2012, we held 142,274 net acres in more than 300 sections (each square mile, a "section") in the Permian-Garden City area, with an average working interest of approximately 94% in all producing wells.

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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 four identified shale zones targeted for horizontal drilling (Upper, Middle and Lower Wolfcamp and Cline shales). Through September 17, 2012, we have drilled and completed 49 horizontal wells in these four horizontal target zones. We have completed 33 horizontal Cline wells and 14 horizontal Upper Wolfcamp wells. Our recent horizontal activity has moved toward drilling longer laterals (up to 7,500 feet) and increased frac density (up to 28 stages) as we continue the optimization of our completion techniques. Through September 2012, we have completed nine horizontal Cline wells and ten horizontal Upper Wolfcamp wells which have at least 30 days of production history. The average 30-day initial production ("IP") per stage of fracture stimulation for the nine horizontal Cline wells is 31 BOE/D per stage. The average 30-day IP per stage of fracture stimulation for the ten horizontal Upper Wolfcamp wells is approximately 30 BOE/D per stage. Additionally, we have completed one horizontal well in each of the Middle and Lower Wolfcamp zones. The one Middle Wolfcamp well that we have completed has a 30-day IP per stage of fracture stimulation of 36 BOE/D. We are still drilling our second Middle Wolfcamp horizontal well. Our first horizontal Lower Wolfcamp well is producing oil but does not have 30 days of production. Based on our technical data and well performance, we believe we have to date confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 50% and 45%, respectively, of our Permian-Garden City acreage. Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage, as reflected in our 2012 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 Granite Wash formation. The Granite Wash is a conventional play requiring 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 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 growth in reserves, production and cash flow.

Since our inception, we have rapidly grown our reserves, production and cash flow through both our drilling program and strategic acquisitions, as evidenced by our July 2011 acquisition of Broad Oak. Our net proved reserves were estimated at 156,453 MBOE as of December 31, 2011, of which 40% were classified as proved developed and 36% as oil. 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. Unless otherwise specifically identified in this prospectus, 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

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regulations of the Securities and Exchange Commission ("SEC") applicable to the periods presented.

Our net average daily production for the six months ended June 30, 2012 was 29,690 BOE/D, 41% of which was oil and 59% 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 and, to a lesser extent, liquids-rich opportunities in the Anadarko Granite Wash.

In 2012, more emphasis has been placed on our horizontal drilling program than in prior periods. Approximately 85% of our planned drilling capital for 2012 will be invested in the Permian Basin, and we are increasingly allocating it towards our horizontal drilling activity. As of September 17, 2012, we had completed 49 gross horizontal Wolfcamp and Cline shale wells in the Permian and 21 gross horizontal Granite Wash wells. The horizontal drilling program comprises an extensive, multi-year, multiple-zone inventory of exploratory and development opportunities.

In December 2011, we completed a corporate reorganization and an initial public offering of Laredo Petroleum Holdings, Inc.'s common stock (the "IPO"). See " Corporate history and structure."

The following table summarizes our net acreage and producing wells as of June 30, 2012, total estimated net proved reserves as of December 31, 2011, and average daily production for the six months ended June 30, 2012 in our principal operating regions. Based on estimates in the report prepared by Ryder Scott, we operate wells that represent approximately 97% of the value of our proved developed oil and natural gas reserves as of December 31, 2011. In addition, the table shows our gross identified potential drilling locations and our proved undeveloped locations as of December 31, 2011.

	At December 31, 2011					Six months ended June 30, 2012	At June 30, 2012		
	Estimated net proved reserves(1)(2)			Identified potential drilling locations(4)		average daily		Producing wells	
	MBOE(3)	% of total reserves	% Oil	Total	PUD locations(5)	production(6) (BOE/D)	Net acreage	Gross	Net
Permian Basin									
Permian Garden City	101,441	65%	52%	5,669	872	19,316	142,274	759	713
Permian Other							45,740		
Anadarko Granite Wash	45,101	29%	8%	335	207	7,931	37,924	184	138
Other Areas(7)	9,911	6%	3%			2,443	71,550	347	174
New Ventures(8)							106,788	1	1
Total	156,453	100%	36%	6,004	1,079	29,690	404,276	1,291	1,026

(1) Our estimated net proved reserves were prepared by Ryder Scott as of December 31, 2011 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 twelve-month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable twelve-month period), held constant throughout the life of the properties. The reference prices were $92.71/Bbl for oil and $3.99/MMBtu for natural gas for the twelve months ended December 31, 2011.

(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, 2011 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 $7.48/Mcf in the Permian area and $4.88/Mcf in the Anadarko Granite Wash area.

(3) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

(4) See the Glossary of Oil and Natural Gas Terms for the definition of "identified potential drilling locations" and "Business Overview" for more information regarding the processes and criteria through which these potential drilling locations were identified.

(5) Represents the number of identified potential drilling locations to which proved undeveloped reserves are attributable.

(6) 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.

(7) Includes our acreage in the gas prone Eastern Anadarko (26,929 net acres) and Central Texas Panhandle (44,621 net acres).

(8) Includes 99,144 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 7,643 net acres in other New Ventures. See 'Business New ventures."

At September 17, 2012, we had a total of 14 operated drilling rigs working. Ten of these rigs were working on our properties in the Permian Basin, six drilling vertical wells and four drilling horizontal wells. Three rigs were working on our properties in the Anadarko Granite Wash, all drilling horizontal wells. One rig was drilling an exploratory well in our New Ventures.

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 horizontal drilling in the Permian Basin and, to a lesser extent, the Anadarko Granite Wash.

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. We have an inventory of approximately 6,000 identified potential drilling locations as of December 31, 2011. As of June 30, 2012, such locations are on 142,274 net acres in the Permian-Garden City area and 37,924 net acres in the Anadarko Granite Wash. We believe this inventory 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 33 horizontal Cline wells and 14 horizontal Upper Wolfcamp wells, we believe we have confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 50% and 45%, respectively, of our Permian-Garden City acreage. 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. This enables us to create a plan to systematically and efficiently develop this acreage position as a resource play. Our future implementation plan will provide flexibility to include potential 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 2012 capital budget allocation.

Capitalize on technical expertise. We intend to leverage 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, and a number of horizontal tests to date, primarily in the Upper Wolfcamp

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and Cline shales in the Permian-Garden City area, we believe we have reduced the risk and uncertainty associated with (or "de-risked") a significant portion of such acreage.

We intend to continue to make substantial 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 emphasizing our horizontal program, we can increase the efficiency of our resource recovery in the multiple vertically stacked producing horizons on our acreage in both our Permian and Anadarko Granite Wash plays. We are drilling 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. 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 and joint ventures. While we believe our multi-year inventory of identified potential drilling locations provides us with significant growth opportunities, we will continue to evaluate strategically compelling asset acquisitions, mergers and joint ventures. Any transaction we pursue will either generally complement our asset base or provide an anticipated competitive economic proposition relative to our existing opportunities or market conditions. Our Laredo-operated joint ventures with ExxonMobil and Linn Energy, our 2008 acquisition of properties from Linn Energy and our 2011 acquisition of Broad Oak are examples of this strategy.

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 significant 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 formation in 2006 through September 17, 2012, we have completed more than 700 gross vertical and 51 gross horizontal wells with a success rate of approximately 99%. Based on this

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drilling success, coupled with our technical data, we have confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 70,000 and 60,000 acres, respectively, of our Permian Basin acreage and are working to de-risk the remaining acreage and zones. As of December 31, 2011, we had identified approximately 5,600 gross potential drilling locations in the Permian-Garden City area, in addition to the 335 gross potential locations in our Anadarko Granite Wash acreage which we believe have 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 potential locations provide a multi-year drilling inventory supporting future growth in reserves, production and cash flow.

Extensive 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 acreage base that includes approximately 740 square miles of 3D seismic data, 130 proprietary petrophysical logs and more than 13,500 historical open-hole logs. On our Permian-Garden City acreage, we have 10 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 700 gross vertical and 51 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 September 17, 2012, approximately 50% of our full-time staff are experienced technical employees, including 24 engineers, 16 geoscientists, 17 landmen and 46 technical support staff.

Significant operational control. We operate wells that represent approximately 97% of the value of our proved developed reserves as of December 31, 2011 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 identified potential drilling locations.

Owned gathering infrastructure. Our wholly-owned subsidiary, Laredo Gas Services, LLC, has invested approximately $64 million in more than 270 miles of pipeline in our natural gas gathering systems in the Permian and Anadarko Basins as of June 30, 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 both of shut-ins awaiting pipeline connection and curtailment by downstream pipelines.

Financial strength and flexibility. We maintain a financial profile that enables operational flexibility. At June 30, 2012, we had approximately $785 million available for borrowings on our senior secured credit facility and total debt of approximately $1.05 billion. Our total debt, less available cash, was approximately $905 million, or approximately 2.0 times our annualized Adjusted EBITDA (a non-GAAP financial measure) for the first six months of 2012. We also use

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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. 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. As of September 30, 2012, we had $50 million outstanding on our senior secured credit facility.

Strong institutional investor support and corporate governance. Our institutional investor, 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. Warburg Pincus did not sell shares of our common stock in the IPO and after this offering will retain a majority interest in Laredo. In addition to the support we receive from Warburg Pincus, we also believe that our board of directors is well qualified and represents a significant resource. Our board, which is comprised of Laredo management and representatives of Warburg Pincus as well as independent individuals, has extensive oil and 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.

Recent developments

Preliminary results for the third quarter ended September 30, 2012. We are finalizing our financial results for the three and nine months ended September 30, 2012. Set forth below are certain preliminary estimates of the results of operations that we expect to report for the third quarter of 2012. Our actual results will be different, and could differ materially, from these estimates due to the completion of our financial closing procedures, final adjustments and other developments that may arise between now and the time the financial results for our third quarter are finalized. All percentage comparisons to the prior year and the second quarter of 2012 are measured at the mid-point of the ranges provided for the third quarter of 2012.

The following are our preliminary estimates for the three months ended September 30, 2012:

- Oil and natural gas production is expected to be between 2,776 MBOE and 2,815 MBOE, a 25% increase from 2,242 MBOE in the corresponding prior-year period and within 98% of the second-quarter 2012 production level.

- Oil and natural gas revenues are expected to be between $136 million and $143 million, a 6% increase from $132 million in the corresponding prior-year period. The estimated increase in revenues is due primarily to an increase in volumes sold.

- At September 30, 2012, we had approximately $28 million of cash and cash equivalents and $735 million of available borrowing capacity on our senior secured credit facility. We anticipate borrowing an additional $50 million on our senior secured credit facility during the week of October 8, 2012.

The estimates above represent the most current information available to management. A range for the preliminary results described above is provided because our financial closing procedures

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for the month and quarter ended September 30, 2012 are not yet complete. As a result, our final results will vary from these preliminary estimates. Such variances may be material; accordingly, you should not place undue reliance on these preliminary estimates. We currently expect that our final results will be within the ranges described above; however, it is possible that they will not be within these ranges. The estimates for the three months ended September 30, 2012 are not necessarily indicative of any future period and should be read together with "Risk factors," "Forward-looking statements," "Management's discussion and analysis of financial condition and results of operations," "Selected historical consolidated financial data" and our audited and unaudited consolidated financial statements and notes thereto included elsewhere in this prospectus.

The preliminary financial and operating data included in this prospectus has been prepared by, and is the responsibility of, our management and has not been reviewed or audited by our independent registered public accounting firm. Accordingly, our independent registered public accounting firm does not express an opinion or any other form of assurance with respect to this preliminary data.

We expect our closing procedures with respect to the quarter ended September 30, 2012 to be completed in November 2012. Accordingly, our financial statements as of and for the three and nine months ended September 30, 2012 will not be available until after this offering is completed.

Borrowing on senior secured credit facility. Refer to Note N to our unaudited consolidated financial statements included elsewhere in this prospectus for further discussion of the borrowing of $50 million on our senior secured credit facility on August 28, 2012.

Other. See "Management's discussion and analysis of financial condition and results of operations," "Business" and "Management Committees of the board of directors Audit committee" for further discussion of our recent developments, including with respect to our core areas of operations and additional derivative contracts.

Risk factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. In particular, the following considerations may offset our competitive strengths or have a negative effect on our business strategy as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

- 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.

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

- 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. Regulation could prohibit or restrict our ability to apply hydraulic fracturing to our wells.

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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.

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.

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

This list is not exhaustive. Please read the full discussion of these risks and other risks described under "Risk factors."

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 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 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. The Corporate Reorganization and IPO are discussed in Notes A and D to our audited consolidated financial statements included elsewhere in this prospectus.

Laredo Petroleum, Inc. is the borrower under our senior secured credit facility as well as the issuer of our $550 million $9^1/_2$% senior unsecured notes due 2019 (the "2019 senior unsecured notes") issued in January and October 2011 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.

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The following diagram depicts our ownership structure after giving effect to this offering assuming no exercise of the underwriters' option to acquire additional shares of common stock.

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. Our website address is www.laredopetro.com. We make our periodic reports and other information filed with or furnished to the SEC available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus.

The offering

Selling stockholders	Affiliates of Warburg Pincus LLC
Common stock offered by the selling stockholders	12,500,000 shares.
	14,375,000 shares, if the underwriters exercise their option to acquire additional shares of common stock in full.
Underwriters' option to purchase additional common stock	1,875,000 shares.
Common stock outstanding after this offering(1)	128,230,576 shares. The number of shares of common stock outstanding will not change as a result of this offering.
Use of proceeds	We will not receive any proceeds from the sale of shares in this offering. See "Use of proceeds."
Dividend policy	We do not anticipate paying any cash dividends on our common stock. In addition, our senior secured credit facility and the indentures governing our senior unsecured notes prohibit us from paying cash dividends. See "Dividend policy."
NYSE symbol	LPI.
Risk factors	Investing in our common stock involves risks. See "Risk factors" for a discussion of certain factors you should consider in evaluating whether or not to invest in our common stock.

(1) The shares to be outstanding after this offering are based on 128,230,576 shares of common stock outstanding as of September 28, 2012 and exclude (i) 485,403 shares issuable upon the exercise of stock options outstanding as of September 28, 2012, with a weighted average exercise price of $24.11 per share, and (ii) 8,812,710 shares reserved for issuance under our 2011 Omnibus Equity Incentive Plan.

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Summary historical consolidated financial data

The following summary historical consolidated financial data should be read in conjunction with "Management's discussion and analysis of financial condition and results of operations" and our unaudited consolidated financial statements and condensed notes thereto and our audited consolidated financial statements and notes thereto included elsewhere in this prospectus. We believe that the assumptions underlying the preparation of our financial statements are reasonable. The financial information included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

Presented below is our summary historical consolidated financial data for the periods and as of the dates indicated. The summary historical consolidated financial data for the years ended December 31, 2011, 2010 and 2009 and the consolidated balance sheets as of December 31, 2011 and 2010 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this prospectus. The summary historical consolidated financial data for the six months ended June 30, 2012 and 2011 and the consolidated balance sheet as of June 30, 2012 are derived from our unaudited consolidated financial statements and the condensed notes thereto included elsewhere in this prospectus. The summary historical consolidated financial data for the year ended December 31, 2008 and the consolidated balance sheet data as of December 31, 2009 and 2008 are derived from our audited consolidated financial statements not included in this prospectus. The summary historical consolidated financial data for the year ended December 31, 2007 and the consolidated balance sheet data as of December 31, 2007 are derived from our unaudited consolidated financial statements not included in this prospectus.

(in thousands, except per share data)	For the six months ended June 30, 2012		For the years ended December 31,				
	2012	2011	2011	2010	2009	2008(1)	2007(2)
	(unaudited)						(unaudited)
Statement of operations data:							
Total revenues	$ 290,972	$ 238,838	$ 510,270	$ 242,000	$ 96,574	$ 74,187	$ 9,628
Total costs and expenses	194,060	131,205	308,371	169,018	350,103	350,653	17,251
Operating income (loss)	96,912	107,633	201,899	72,982	(253,529)	(276,466)	(7,623)
Non-operating income (expense), net	(7,521)	(36,154)	(36,971)	(12,546)	(4,972)	30,702	167
Income (loss) before income taxes	89,391	71,479	164,928	60,436	(258,501)	(245,764)	(7,456)
Net income (loss)	57,210	45,742	105,554	86,248	(184,495)	(192,047)	(6,051)
Pro forma net income per common share:							
Basic	$ 0.45		$ 0.98				
Diluted	$ 0.45		$ 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.

(2) The year ended December 31, 2007 contains the results of operations for the acquisition of properties from Jones Energy beginning June 5, 2007, the closing date of the property acquisition.

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(in thousands)	As of June 30, 2012	As of December 31, 2011	2010	2009	2008	2007
	(unaudited)					(unaudited)
Balance sheet data:						
Cash and cash equivalents	$ 146,485	$ 28,002	$ 31,235	$ 14,987	$ 13,512	$ 6,937
Net property and equipment	1,756,405	1,378,509	809,893	396,100	350,702	137,852
Total assets	2,115,938	1,627,652	1,068,160	625,344	578,387	171,799
Current liabilities	224,026	214,361	150,243	79,265	101,864	16,809
Long-term debt	1,051,863	636,961	491,600	247,100	148,600	44,500
Stockholders' / unit holders' equity	822,058	760,013	411,099	289,107	318,364	109,707

(in thousands)	For the six months ended June 30, 2012	2011	For the years ended December 31, 2011	2010	2009	2008	2007
	(unaudited)						(unaudited)
Other financial data:							
Net cash provided by operating activities	$ 199,790	$ 162,058	$ 344,076	$ 157,043	$ 112,669	$ 25,332	$ 5,019
Net cash used in investing activities	(485,831)	(359,449)	(706,787)	(460,547)	(361,333)	(490,897)	(131,153)
Net cash provided by financing activities	404,524	188,208	359,478	319,752	250,139	472,140	126,726

(in thousands, unaudited)	For the six months ended June 30, 2012	2011	For the years ended December 31, 2011	2010	2009	2008	2007
Adjusted EBITDA(1)	$ 227,821	$ 183,796	$ 388,446	$ 194,502	$ 104,908	$ 49,305	$ (1,522)

(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 "Selected historical consolidated financial data Non-GAAP financial measures and reconciliations."

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Summary historical reserve data

The following table sets forth certain unaudited information concerning our proved oil and natural gas reserves as of December 31, 2011 based on estimates in a reserve report prepared by Ryder Scott, our independent reserve engineers. 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. Reserves cannot be measured exactly because reserve estimates involve subjective judgments. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes.

	December 31, 2011 Reserve category			
	PDP	**PDNP**	**PUD**	**Total**
Proved Reserves:				
Oil and condensate (MBbls)	20,882	880	34,505	56,267
Natural gas (MMcf)	232,495	16,103	352,519	601,117
Oil equivalents(1) (MBOE)	59,631	3,564	93,258	156,453
% Oil and condensate	35%	25%	37%	36%
% Natural gas	65%	75%	63%	64%

(1) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

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Risk factors

Investing in our common stock involves a high degree of risk. You should carefully consider the risks and uncertainties described below, as well as other information contained in this prospectus, before purchasing our common stock. If any of the following risks actually occur, our business, financial condition, operating results or cash flow could be materially and adversely affected. Additional risks and uncertainties not presently known to us or not believed by us to be material may also negatively impact 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 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

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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 or 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;

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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 62% of our total estimated proved reserves as of December 31, 2011, 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 intends to release an interim report by late 2012 and a final report in 2014 synthesizing the longer-term research projects.

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On April 17, 2012, the EPA issued a final rule that subjects 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 EPA's final rule includes NSPS standards for completions of hydraulically fractured 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 becomes effective October 15, 2012; however, a number of the requirements will 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 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 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. Furthermore, on May 4, 2012, 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. 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.

A committee of the House of Representatives is conducting an investigation of hydraulic fracturing practices. Further, certain members of Congress have called upon: (i) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (ii) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and (iii) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. The Shale Gas Subcommittee of the Secretary of Energy Advisory Board released an interim report on August 11, 2011, proposing recommendations to reduce the potential environmental impacts from shale gas production. On November 18, 2011, the Subcommittee issued its final report, which focuses on implementation of the interim report's recommendations. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, 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 (the "RRC") 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 prospectus 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 crude oil, natural gas and natural gas liquids 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 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.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would 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 noncash charge to earnings. See Note P.4 in our audited consolidated financial statements included elsewhere in this prospectus.

Our identified potential drilling locations 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.

Our management team has specifically identified and scheduled certain potential drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these potential drilling 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 system, 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 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 identified.

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

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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.9 to our audited consolidated financial statements included elsewhere in this prospectus 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 significant 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 September 30, 2012, we have entered into hedge contracts for approximately 5.1 million Bbls of our crude oil production and 59.8 million MMBtu of our natural gas production for settlement between October 2012 and December 2015. We are currently realizing a significant 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 "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.

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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 $31.1 million at June 30, 2012) and the sale of our oil and natural gas production (approximately $38.9 million in receivables at June 30, 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 36% of our total oil and natural gas revenues for the six months ended June 30, 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:

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

terrorist attacks targeting oil and natural gas related facilities and infrastructure.

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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 prospectus, 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

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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.

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 "Business Regulation of the oil and natural gas industry" for a further description of the laws and regulations that affect us.

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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 "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

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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,

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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, 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 are not yet effective will take effect, depending on the rule, on October 12, 2012, October 14, 2012, January 10, 2013 or April 10, 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. Certain bona fide hedging transactions or positions are exempt from these position limits. 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. This 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.

Many of the anticipated benefits of acquiring Broad Oak may not be realized.

Laredo acquired Broad Oak in July 2011 with the expectation that the acquisition would result in various benefits, including, among other things, incremental scale and significant additional

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exposure to attractive vertical and horizontal oil and liquids-rich natural gas opportunities. However, to realize these anticipated benefits, we must successfully integrate Broad Oak into Laredo. If we are not able to achieve these objectives, the anticipated benefits of the acquisition may not be realized fully or at all or may take longer to realize than expected. It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees or the disruption of our ongoing businesses or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, which could adversely affect our ability to achieve the anticipated benefits of the acquisition. Our consolidated results of operations could also be adversely affected by any issues attributable to either company's operations that arise or are based on events or actions that occurred prior to the closing of the acquisition. Laredo may have difficulty addressing possible differences in corporate cultures and management philosophies. Integration efforts will also divert management attention and resources. These integration activities could have an adverse effect on our business during the transition period. The integration process is subject to a number of uncertainties and no assurance can be given regarding when, or even if, the anticipated benefits will be realized. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect Laredo's future business, financial condition, operating results and prospects.

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.

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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 September 28, 2012, Warburg Pincus owns approximately 79.4% of our outstanding common stock, and upon completion of this offering (assuming the underwriters exercise their option to acquire additional shares in full), Warburg Pincus will own approximately 68.3% of our outstanding common stock. We believe that Warburg Pincus' substantial ownership interest in us provides them with an economic incentive to assist us to be successful. However, subject to the restrictions set forth in the lock-up agreement that Warburg Pincus will enter into in connection with this offering, Warburg Pincus is not obligated to maintain its ownership interest in us following this offering 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.

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 September 30, 2012, we have approximately $735 million of

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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 $785 million available on our senior secured credit facility would result in increased annual interest expense of approximately $7.9 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.

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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 "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 June 30, 2012, five customers accounted for 10% or greater of our oil and gas sales receivables: 40%, 18%, 14%, 13% and 13%. 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 September 30, 2012, we had total long-term indebtedness of approximately $1.1 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

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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 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.

The President's proposed budget for fiscal year 2013 contains a proposal to 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

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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 the budget proposal or any other similar change in U.S. federal income tax law could eliminate 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 this offering and ownership of our common stock

The market price of our common stock may be volatile, and your investment in our stock could suffer a decline in value.

The market price of our common stock could fluctuate significantly due to a number of factors, including, but not limited to:

- our quarterly or annual earnings, or those of other companies in our industry;

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- actual or anticipated fluctuations in our operating results;
- changes in accounting standards, policies, guidance, interpretations or principles;
- public reaction to our press releases, our other public announcements and our filings with the SEC;
- announcements by us or our competitors of significant acquisitions, dispositions, innovations, or new programs and services;
- changes in financial estimates and recommendations by securities analysts following our stock, or the failure of securities analysts to cover our common stock after this offering;
- changes in earnings estimates by securities analysts or our ability to meet those estimates;
- the operating and stock price performance of other comparable companies;
- general economic conditions and overall market fluctuations;
- the trading volume of our common stock;
- changes in business, legal or regulatory conditions, or other developments affecting participants in, and publicity regarding our business or any of our significant customers or competitors;
- results of operations that vary from the expectations of securities analysts and investors or those of our competitors;
- the failure of securities analysts to publish research about us after this offering or to make changes in their financial estimates;
- future sales of our common stock by us, directors, executives and significant stockholders; and
- changes in economic and political conditions in our markets.

In particular, the realization of any of the risks described in these "Risk factors" could have a material and adverse impact on the market price of our common stock in the future and cause the value of your investment to decline. In addition, the stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock over the short, medium or long term, regardless of our actual performance. If the market price of our common stock reaches an elevated level following this offering, it may materially and rapidly decline. In the past, following periods of volatility in the market price of a company's securities, stockholders have often instituted securities class action litigation. If we were to be involved in a class action lawsuit, it could divert the attention of senior management and, if adversely determined, have a material adverse effect on our business, results of operations and financial condition.

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Your percentage ownership in us may be diluted by future issuances of common stock or securities or instruments that are convertible into our common stock, which could reduce your influence over matters on which stockholders vote.

Our board of directors has the authority, without action or vote of our stockholders, to issue all or any part of our authorized but unissued shares of common stock, including shares issuable upon the exercise of options, shares that may be issued to satisfy our obligations under our incentive plans, shares of our authorized but unissued preferred stock and securities and instruments that are convertible into or exchangeable for our common stock. Issuances of common stock or voting preferred stock would reduce your influence over matters on which our stockholders vote and, in the case of issuances of preferred stock, likely would result in your interest in us being subject to the prior rights of holders of that preferred stock.

The requirements of being a public company may strain our resources and divert management's attention.

We are subject to the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"), Dodd-Frank, the listing requirements of the NYSE and other applicable securities rules and regulations. Compliance with these rules and regulations has increased and will continue to increase our legal and financial compliance costs, make some activities more difficult, time consuming or costly, and increase demand on our systems and resources. The SEC recently adopted rules under Dodd-Frank that require each "resource extraction issuer" to publicly disclose information relating to any payment of $100,000 or more made by the issuer to the U.S. or a foreign government for the purpose of the commercial development of oil, natural gas or minerals. While the rules will become effective on November 13, 2012, our first report under the rules will be required for fiscal year ending December 31, 2013, which will cover the partial effective period from October 1, 2013 to year end. The Sarbanes-Oxley Act requires, among other things, that we maintain effective disclosure controls and procedures and internal control over financial reporting. In order to maintain and, if required, improve our disclosure controls and procedures and internal control over financial reporting to meet this standard, significant resources and management oversight may be required. As a result, management's attention may be diverted from other business concerns, which could harm our business and operating results. We may need to hire additional employees in the future to comply with these requirements, which will increase our costs and expenses.

In addition, changing laws, regulations and standards relating to corporate governance and public disclosure are creating uncertainty for public companies, increasing legal and financial compliance costs and making some activities more time consuming. These laws, regulations and standards are subject to varying interpretations, in many cases due to their lack of specificity, and, as a result, their application in practice may evolve over time as new guidance is provided by regulatory and governing bodies. This could result in continuing uncertainty regarding compliance matters and higher costs necessitated by ongoing revisions to disclosure and governance practices. We invest resources to comply with evolving laws, regulations and standards, and this investment may result in increased general and administrative expenses and a diversion of management's time and attention from revenue-generating activities to compliance activities. If our efforts to comply with new laws, regulations and standards differ from the activities intended by regulatory or governing bodies due to ambiguities related to practice, regulatory authorities may initiate legal proceedings against us and our business may be adversely affected.

We do not anticipate paying any dividends on our common stock in the foreseeable future. As a result, you will need to sell your shares of common stock to receive any income or realize a return on your investment.

We do not anticipate paying any dividends on our common stock in the foreseeable future. Any declaration and payment of future dividends to holders of our common stock may be limited by the provisions of the Delaware General Corporation Law and certain restrictive covenants in our senior secured credit facility and the indentures governing our senior unsecured notes. The future payment of dividends will be at the sole discretion of our board of directors and will depend on many factors, including our earnings, capital requirements, financial condition and other considerations that our board of directors deem relevant. As a result, to receive any income or realize a return on your investment, you will need to sell your shares of common stock. You may not be able to sell your shares of common stock at or above the price you paid for them.

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.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock and to determine the designations, powers, preferences and relative, participating, optional, or other special rights, if any, and the qualifications, limitations, or restrictions of our preferred stock, including the number of shares, in any series, 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.

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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.

For a further description of these provisions of our amended and restated certificate of incorporation, amended and restated bylaws, and Delaware law, see "Description of capital stock Anti-takeover effects of provisions of our certificate of incorporation, our bylaws and Delaware law."

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

Upon completion of this offering (assuming no exercise of the underwriters' option to acquire additional shares of common stock), Warburg Pincus will own approximately 69.7% of our outstanding common stock. Consequently, Warburg Pincus will continue to have 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 will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

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, among other things, in 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. See " Our amended and restated certificate of incorporation contains a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or prospects."

Our amended and restated certificate of incorporation contains a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or prospects.

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,

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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.

As a result, Warburg Pincus or its affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, 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. See "Description of capital stock Corporate opportunity."

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities. Our amended and restated certificate of incorporation authorizes us to issue 450,000,000 shares of common stock, of which 128,230,576 shares are and will be outstanding upon consummation of this offering. This number includes 20,125,000 shares registered and sold in the IPO and up to 14,375,000 shares that the selling stockholders are selling in this offering (assuming the underwriters exercise their option to acquire additional shares in full), which will be freely transferable without restriction or further registration under the Securities Act of 1933, as amended (the "Securities Act"). Of the remaining shares, 90,574,391 shares, including the shares of common stock owned by Warburg Pincus upon completion of this offering (assuming the underwriters exercise their option to acquire additional shares in full) and the shares of common stock owned by our directors and executive officers, will be restricted from immediate resale under the federal securities laws and in some cases by the lock-up agreements between the selling stockholders, our directors and executive officers, and the underwriters, which generally provide for a lock-up period of 60 days following the date of this prospectus (unless the representatives of the underwriters waive such lock-up period), but may be sold in the near future. See "Underwriting." Following the expiration of the applicable lock-up period, all these shares of our common stock will be eligible for resale under Rule 144 of the Securities Act, subject to volume limitations and applicable holding period requirements. In addition, Warburg Pincus will have the ability to cause us to register the resale of its shares, and Mr. Foutch will have the ability to include his shares in the registration. See "Shares eligible for future sale" for a discussion of the shares of our common stock that may be sold into the public market in the future.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments and pursuant to compensation and incentive plans. If any such acquisition or investment is significant, the number of shares of our

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common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities issued in connection with any such acquisitions and investments.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition or compensation or incentive plan), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

We are a "controlled company" within the meaning of the NYSE rules and, if applicable, would qualify for and could rely on exemptions from certain corporate governance requirements.

Upon the closing of this offering, Warburg Pincus will continue to control a majority of our voting common stock. As a result, we will continue to be a "controlled company" as that term is set forth in Section 303A of the NYSE Listed Company Manual. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a "controlled company" and may elect not to comply with certain NYSE corporate governance requirements, including:

- the requirement that a majority of our board of directors consist of independent directors;
- the requirement that our nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- the requirement that our compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

These requirements will not apply to us as long as we remain a "controlled company." We may utilize some or all of these exemptions in the future. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. Warburg Pincus' significant ownership interest could adversely affect investors' perceptions of our corporate governance.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income.

If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code, our ability to offset taxable income arising after the ownership change with net operating losses ("NOLs") arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. Although we do not expect that the offering itself will result in an ownership change, without taking into account the effects or likelihood of future transactions in our common stock, we could be nearing the ownership change threshold upon completion of this offering. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Internal Revenue Code) at any time during a rolling three-year period.

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Forward-looking statements

This prospectus contains "forward-looking statements." Such statements can generally be identified by the use of forward-looking terminology such as "could," "believe," "anticipate," "intend," "estimate," "expect," "project," "may," "will," "should," "plan," "predict," "potential," "foresee," "goal," "pursue," "target," "continue," "suggest" or the negative thereof or other variations thereon or comparable terminology, or by discussions of strategy. Investors are cautioned that any such forward-looking statements are not guarantees of future performance and may involve significant risks and uncertainties, and that actual results may vary materially from those in the forward-looking statements as a result of various factors. 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 gas reserves, including our expectations that estimates of our proved reserves will increase;
- competition in the oil and gas industry;
- availability and costs of drilling and production equipment, labor, and oil and gas processing and other services;
- 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;
- 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; 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 prospectus under "Risk factors," in "Management's discussion and analysis of financial condition and results of operations" and elsewhere in this prospectus. In light of such risks and uncertainties, we caution you not to place undue reliance on these forward-looking statements in deciding whether to invest in our common stock.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas that are ultimately recovered.

These forward-looking statements speak only as of the date of this prospectus, and we do not undertake any obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances after the date of this prospectus or to reflect the occurrence of unanticipated events, except as required by applicable securities laws.

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Use of proceeds

We will not receive any of the proceeds from the sale of shares by the selling stockholders in this offering. See "Principal and selling stockholders."

Dividend policy

We have not declared or paid cash dividends to holders of our common stock and do not anticipate declaring or paying any cash dividends in the foreseeable future. We currently intend to retain our future earnings, if any, to support the growth and development of our business. The payment of future cash dividends, if any, will be at the discretion of our board of directors and will depend upon, among other things, our financial condition, results of operations, capital requirements and development expenditures, future business prospects and any restrictions imposed by future debt instruments. In addition, our senior secured credit facility and the indentures governing our senior unsecured notes prohibit us from paying cash dividends.

Market price of our common stock

In connection with the closing of our IPO in December 2011, we listed our common stock on the NYSE under the symbol "LPI." The first quarter of 2012 was the first full quarter in which our common stock traded on the NYSE. On October 4, 2012, the last reported sale price for our common stock on the NYSE was $21.96 per share. As of September 28, 2012, we had approximately 128,230,576 shares of common stock issued and outstanding and 4,839 stockholders of record. The following table sets forth, for the periods indicated, the reported high and low sale prices for our common stock on the NYSE.

	Common Stock	
	High	**Low**
2012:		
First Quarter	$ 27.91	$ 19.78
Second Quarter	$ 26.87	$ 18.29
Third Quarter	$ 24.10	$ 20.44

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Capitalization

The following table sets forth the capitalization of Laredo Petroleum Holdings, Inc. as of June 30, 2012 on an actual basis.

You should read the following table in conjunction with "Selected historical consolidated financial data," "Management's discussion and analysis of financial condition and results of operations" and our consolidated financial statements and notes thereto included elsewhere in this prospectus.

(in thousands)		**As of June 30, 2012 Actual**
		(unaudited)
Cash and cash equivalents	$	146,485
Long-term debt, including current maturities		
Senior secured credit facility(1)	$	
Senior unsecured notes due 2019	$	551,863
Senior unsecured notes due 2022	$	500,000
Stockholders' equity	$	822,058
Total capitalization	$	1,873,921

(1) As of September 30, 2012, we had $50 million outstanding under our senior secured credit facility.

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Selected historical consolidated financial data

The following historical consolidated financial data should be read in conjunction with "Management's discussion and analysis of financial condition and results of operations" and our unaudited consolidated financial statements and condensed notes thereto and our audited consolidated financial statements and notes thereto included elsewhere in this prospectus. We believe that the assumptions underlying the preparation of our financial statements are reasonable. The financial information included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

Presented below is our historical consolidated financial data for the periods and as of the dates indicated. The historical consolidated financial data for the years ended December 31, 2011, 2010 and 2009 and the consolidated balance sheets as of December 31, 2011 and 2010 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this prospectus. The historical consolidated financial data for the six months ended June 30, 2012 and 2011 and the consolidated balance sheet as of June 30, 2012 are derived from our unaudited consolidated financial statements and the condensed notes thereto included elsewhere in this prospectus. The historical consolidated financial data for the year ended December 31, 2008 and the consolidated balance sheet data as of December 31, 2009 and 2008 are derived from our audited consolidated financial statements not included in this prospectus. The historical consolidated financial data for the year ended December 31, 2007 and the consolidated balance sheet data as of December 31, 2007 are derived from our unaudited consolidated financial statements not included in this prospectus.

(in thousands, except per share data)	For the six months ended June 30, 2012		For the years ended December 31,				
	2012	2011	2011	2010	2009	2008(1)	2007(2)
	(unaudited)						(unaudited)
Statement of operations data:							
Total revenues	$ 290,972	$ 238,838	$ 510,270	$ 242,000	$ 96,574	$ 74,187	$ 9,628
Total costs and expenses	194,060	131,205	308,371	169,018	350,103	350,653	17,251
Operating income (loss)	96,912	107,633	201,899	72,982	(253,529)	(276,466)	(7,623)
Non-operating income (expense), net	(7,521)	(36,154)	(36,971)	(12,546)	(4,972)	30,702	167
Income (loss) before income taxes	89,391	71,479	164,928	60,436	(258,501)	(245,764)	(7,456)
Net income (loss)	57,210	45,742	105,554	86,248	(184,495)	(192,047)	(6,051)
Pro forma net income per common share:							
Basic	$ 0.45		$ 0.98				
Diluted	$ 0.45		$ 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.

(2) The year ended December 31, 2007 contains the results of operations for the acquisition of properties from Jones Energy beginning June 5, 2007, the closing date of the property acquisition.

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(in thousands)	As of June 30, 2012	2011	2010	2009	2008	As of December 31, 2007
	(unaudited)					(unaudited)
Balance sheet data:						
Cash and cash equivalents	$ 146,485	$ 28,002	$ 31,235	$ 14,987	$ 13,512	$ 6,937
Net property and equipment	1,756,405	1,378,509	809,893	396,100	350,702	137,852
Total assets	2,115,938	1,627,652	1,068,160	625,344	578,387	171,799
Current liabilities	224,026	214,361	150,243	79,265	101,864	16,809
Long-term debt	1,051,863	636,961	491,600	247,100	148,600	44,500
Stockholders' / unit holders' equity	822,058	760,013	411,099	289,107	318,364	109,707

(in thousands)	For the six months ended June 30, 2012	2011	For the years ended December 31, 2011	2010	2009	2008	2007
	(unaudited)						(unaudited)
Other financial data:							
Net cash provided by operating activities	$ 199,790	$ 162,058	$ 344,076	$ 157,043	$ 112,669	$ 25,332	$ 5,019
Net cash used in investing activities	(485,831)	(359,449)	(706,787)	(460,547)	(361,333)	(490,897)	(131,153)
Net cash provided by financing activities	404,524	188,208	359,478	319,752	250,139	472,140	126,726

(in thousands, unaudited)	For the six months ended June 30, 2012	2011	For the years ended December 31, 2011	2010	2009	2008	2007
Adjusted EBITDA(1)	$ 227,821	$ 183,796	$ 388,446	$ 194,502	$ 104,908	$ 49,305	$ (1,522)

(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 financing fees and other, gains or losses on sale of assets, unrealized gains or losses on derivative financial instruments, realized losses on interest rate derivatives, non-cash equity and stock-based compensation and income tax expense or benefit. Adjusted EBITDA, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDA should not be considered in isolation or as a substitute for operating income or loss, net income or loss, cash flows provided by operating activities, used in investing activities and provided by financing activities, or statement of operations or statement of cash flow data prepared in accordance with GAAP. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital increases, working capital decreases or its tax position. Adjusted EBITDA does not represent funds available for discretionary use, because those funds are required for debt service,

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capital expenditures and working capital, income taxes, franchise taxes and other commitments and obligations. However, our management team 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 team for various purposes, including as a measure of operating performance, in presentations to our board of directors, and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies, and the 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 six months ended June 30,		**For the years ended December 31,**				
(in thousands, unaudited)	**2012**	**2011**	**2011**	**2010**	**2009**	**2008**	**2007**
Net income (loss)	$ 57,210	$ 45,742	$ 105,554	$ 86,248	$ (184,495)	$ (192,047)	$ (6,051)
Plus:							
Interest expense	36,358	22,252	50,580	18,482	7,464	4,410	2,046
Depreciation, depletion and amortization	112,220	75,917	176,366	97,411	58,005	33,102	4,986
Impairment of long-lived assets		243	243		246,669	282,587	
Write-off of deferred loan costs		3,246	6,195				
Loss on disposal of assets	8	35	40	30	85	2	
Unrealized losses (gains) on derivative financial instruments	(16,929)	7,192	(20,890)	11,648	46,003	(27,174)	(1,098)
Realized losses on interest rate derivatives	1,938	2,556	4,873	5,238	3,764	278	
Non-cash equity and stock-based compensation	4,835	876	6,111	1,257	1,419	1,864	
Income tax expense (benefit)	32,181	25,737	59,374	(25,812)	(74,006)	(53,717)	(1,405)
Adjusted EBITDA	$ 227,821	$ 183,796	$ 388,446	$ 194,502	$ 104,908	$ 49,305	$ (1,522)

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 prospectus. 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 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 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 prospectus, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Forward-looking statements" and "Risk factors."

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 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, whereby Broad Oak became a wholly-owned subsidiary of Laredo Petroleum, 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.

Our financial and operating performance for the six months ended June 30, 2012 included the following:

- Oil and natural gas sales of approximately $288.6 million, compared to approximately $236.5 million for the six months ended June 30, 2011;
- Average daily production of 29,690 BOE/D, compared to 22,070 BOE/D for the six months ended June 30, 2011; and
- Adjusted EBITDA (a non-GAAP financial measure) of $227.8 million compared to $183.8 million for the six months ended June 30, 2011.

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.

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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 generally seek acquisitions in core, mature areas where management can leverage knowledge and experience to identify upsides in assets.

On May 30, 2008 and August 6, 2008, we entered into purchase and sale agreements with Linn Energy to acquire ownership interests in oil and gas properties located in the Verden area in Caddo, Grady and Comanche Counties, Oklahoma, for a total purchase price of $185.0 million, subject to certain adjustments. The first purchase and sale agreement had an effective date of July 1, 2008, and was closed on August 15, 2008. The second purchase and sale agreement completed the acquisition of the remaining property, had an effective date of July 1, 2008 and was closed on August 7, 2008. There were no significant acquisitions during 2009 and 2010.

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. Refer to Note A to our audited consolidated financial statements included elsewhere in this prospectus for further discussion of the Broad Oak acquisition.

On July 12, 2012, we completed the acquisition of additional working interest in certain oil and natural gas properties located in Glasscock County, Texas for a total purchase price of $20.5 million from a private company, subject to certain purchase price adjustments.

Core areas of operations

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 June 30, 2012, we have assembled 188,014 net acres in the Permian Basin and 37,924 net acres in the Anadarko Granite Wash.

Reserves and pricing

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 significantly affect the economic viability of drilling projects, as well as the economic valuation and economic recovery of oil and natural gas reserves.

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Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves at December 31, 2011 and 2010. Ryder Scott also estimated the proved reserves for the legacy Laredo properties as of December 31, 2009. Ryder Scott did not perform evaluations of the Broad Oak properties as of December 31, 2009. Our estimates of the proved reserves at December 31, 2009 are a combination of the Ryder Scott reports on the legacy Laredo properties and Laredo's internal proved reserve estimates of the Broad Oak properties. Based upon the reserve estimates we calculated for Broad Oak, we believe the legacy Laredo properties represented 92% of such combined proved reserves at year end 2009.

The unweighted arithmetic average first-day-of-the-month index prices for the prior 12 months ended June 30, 2012 and June 30, 2011 used to value our reserves were $92.17 per Bbl for oil and $3.01 per MMBtu for natural gas, and $86.60 per Bbl for oil and $4.00 per MMBtu for natural gas, respectively. As of December 31, 2011, we had 156,453 MBOE of estimated net proved reserves as compared to 136,560 MBOE of estimated net proved reserves at December 31, 2010 and 52,519 MBOE of estimated net proved reserves at December 31, 2009. The unweighted arithmetic average first-day-of-the-month index prices for the prior 12 months were $92.71 per Bbl for oil and $3.99 per MMBtu for natural gas at December 31, 2011, $75.96 per Bbl for oil and $4.15 per MMBtu for natural gas at December 31, 2010, and $57.04 per Bbl for oil and $3.15 per MMBtu for natural gas at December 31, 2009. The prices used to estimate proved reserves for all periods did not give effect to derivative transactions, 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 gas production as discussed in " Hedging" below.

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 six months ended June 30, 2012, our revenues are comprised of sales of approximately 70% oil, 29% natural gas and 1% for transportation and treating. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Hedging

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; therefore, the unrealized gains and losses on open positions are reflected currently 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 six months ended June 30, 2012 and 2011, we recognized an unrealized gain on our commodity derivatives of

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$15.3 million and an unrealized loss of $8.7 million on our commodity derivatives, respectively, based on market price fluctuations compared to prices in our commodity derivative contracts.

Subsequent to June 30, 2012, we entered into 15 additional derivative contracts to hedge the price risk associated with approximately 8,760,000 MMBtu, 11,160,000 MMBtu and 15,480,000 MMBtu of our natural gas production for the twelve months ending December 31, 2013, 2014 and 2015, respectively. These derivative contracts have associated deferred premiums totaling approximately $4.2 million. See Note N to our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding these derivative contracts.

Our hedged positions as of June 30, 2012 are as follows:

	Remaining year 2012	Year 2013	Year 2014	Year 2015	Total
Oil(1)					
Total volume hedged with ceiling price (Bbls)	969,000	1,368,000	726,000	252,000	3,315,000
Weighted average ceiling price ($/Bbl)	$ 108.81	$ 110.55	$ 129.09	$ 135.00	$ 115.96
Total volume hedged with floor price (Bbls)	1,305,000	2,448,000	1,266,000	708,000	5,727,000
Weighted average floor price ($/Bbl)	$ 79.90	$ 77.19	$ 75.26	$ 75.00	$ 77.11
Natural Gas(2)					
Total volume hedged with ceiling price (MMBtu)	5,140,000	7,300,000	6,960,000		19,400,000
Weighted average ceiling price(3) ($/MMBtu)	$ 5.54	$ 6.72	$ 7.03	$	$ 6.51
Total volume hedged with floor price (MMBtu)	7,300,000	13,900,000	6,960,000		28,160,000
Weighted average floor price(3) ($/MMBtu)	$ 4.59	$ 3.95	$ 4.00	$	$ 4.13
Natural Gas basis swaps (MMbtu)					
Total volume hedged(4) (MMBtu)	1,440,000	1,200,000			2,640,000
Weighted average price ($/MMBtu)	$ 0.31	$ 0.33	$	$	$ 0.32

(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 or the Panhandle Eastern Pipe Line 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 June 30, 2012, we had 200,000 MMBtu for the remainder of 2012 and 500,000 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 June 30, 2012 hedge positions.

(4) Total volume hedged for natural gas basis swaps includes 200,000 MMBtu for the remainder of 2012 and 500,000 MMBtu for 2013 in basis swaps that did not have corresponding volumes hedged with a NYMEX index price at June 30, 2012.

Principal components of our cost structure

Lease operating and natural gas transportation and treating expenses. These are daily costs incurred to bring oil and 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 gas properties.

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Production and ad valorem taxes. Production taxes are paid on produced oil and 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 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 rig fees. These are costs incurred under short-term drilling contracts for fees paid to various third parties if we terminate our drilling or cease efforts, including for stacked drilling rigs in lieu of drilling.

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.

Equity and stock-based compensation. These are costs incurred for compensation expense related to employee unit awards granted prior to December 19, 2011 and employee stock awards granted on or after December 19, 2011, 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 costs 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.

Impairment expense. This is the cost to reduce proved oil and 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.

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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; 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, in light of the historic ownership structure of Laredo, 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.

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Results of operations

The following table sets forth information regarding production, average sales prices and average costs per BOE for the six months ended June 30, 2012 and 2011 and the years ended December 31, 2011, 2010 and 2009:

	Six months ended June 30,		Years ended December 31,		
	2012	2011	2011	2010	2009
Production data:					
Oil and condensate (MBbl)	2,231	1,517	3,368	1,648	513
Natural gas (MMcf)	19,034	14,866	31,711	21,381	18,302
Oil equivalents (MBOE)(1)(2)	5,404	3,995	8,654	5,212	3,563
Average daily production (BOE/d)	29,690	22,070	23,709	14,278	9,762
% Oil and condensate	41%	38%	39%	32%	14%
Average sales prices:					
Oil and condensate, realized(3) ($/Bbl)	$ 91.23	$ 94.57	$ 91.00	$ 77.00	$ 58.37
Natural gas, realized(3) ($/Mcf)	4.47	6.26	6.30	5.28	3.52
Oil equivalents, realized ($/BOE)	53.40	59.21	58.50	46.01	26.48
Oil and condensate, hedged(4) ($/Bbl)	90.20	90.31	88.62	77.26	65.42
Natural gas, hedged(4) ($/Mcf)	5.31	6.63	6.67	6.32	6.17
Oil equivalents, hedged ($/BOE)	55.95	58.97	58.93	50.37	41.10
Average costs per BOE:					
Lease operating expenses	$ 5.67	$ 4.53	$ 5.00	$ 4.16	$ 3.52
Production and ad valorem taxes	3.00	3.75	3.70	3.01	1.72
General and administrative(5)	5.91	4.95	5.90	5.93	6.34
DD&A	20.77	19.00	20.38	18.69	16.28
Total	$ 35.35	$ 32.23	$ 34.98	$ 31.79	$ 27.86

(1) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

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

(3) 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.

(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. See Note G.4 to our audited consolidated financial statements and Note F.4 to our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding our realized gains and losses on commodity derivatives.

(5) General and administrative includes non-cash, stock-based compensation of $4.8 million and $0.9 million for the six months ended June 30, 2012 and 2011, respectively, and $6.1 million, $1.3 million and $1.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. Excluding stock-based compensation from the above metric results in average general and administrative cost per BOE of $5.02 and $4.73 for the six months ended June 30, 2012 and 2011, respectively, and $5.19, $5.69 and $5.94 for the years ended December 31, 2011, 2010 and 2009, respectively.

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Six months ended June 30, 2012 as compared to the six months ended June 30, 2011

The following table sets forth selected operating data for the six months ended June 30, 2012 compared to the six months ended June 30, 2011:

	Six months ended June 30,	
(in thousands)	**2012**	**2011**
Revenues		
Oil	$ 203,529	$ 143,464
Natural gas	85,031	93,068
Natural gas transportation and treating	2,412	2,306
Total revenues	290,972	238,838
Costs and expenses		
Lease operating expenses	30,644	18,112
Production and ad valorem taxes	16,237	14,999
Natural gas transportation and treating	691	1,167
Drilling and production	1,771	693
General and administrative (including non-cash stock-based compensation of $4,835 and $876 for the six months ended June 30, 2012 and 2011, respectively)	31,941	19,770
Accretion of asset retirement obligations	556	304
Depreciation, depletion and amortization	112,220	75,917
Impairment expense		243
Total costs and expenses	194,060	131,205
Non-operating income (expense):		
Realized and unrealized gain (loss):		
Commodity derivative financial instruments, net	29,137	(9,585)
Interest rate derivatives, net	(323)	(1,094)
Interest expense	(36,358)	(22,252)
Interest and other income	31	58
Write-off of deferred loan costs		(3,246)
Loss on disposal of assets	(8)	(35)
Non-operating expense, net	(7,521)	(36,154)
Income tax expense	(32,181)	(25,737)
Net income	$ 57,210	$ 45,742

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $52.0 million, or 22%, to $288.6 million during the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Our revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 7,620 BOE/D during the six months ended June 30, 2012 as compared to the same period in 2011. The total increase in revenue of approximately $52.0 million is largely attributable to higher oil and natural gas production volumes for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Production increased by 714 MBbls for oil and 4,168 MMcf for natural gas for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. The net dollar effect of the

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decrease in prices of approximately $41.5 million (calculated as the change in period-to-period average prices times current year-to-date production volumes for oil and natural gas) and the net dollar effect of the increase in production of approximately $93.6 million (calculated as the increase in period-to-period volumes for oil and natural gas times the prior period average prices) are shown below.

	Change in prices(1)	Production volumes for the six months ended 6/30/2012(2)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ (3.34)	2,231	$ (7,452)
Natural gas	$ (1.79)	19,034	$ (34,071)
Total revenues due to change in price			$ (41,523)

	Change in production volumes(2)	Prices at 6/30/2011(1)	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	714	$ 94.57	$ 67,523
Natural gas	4,168	$ 6.26	$ 26,092
Total revenues due to change in volumes			$ 93,615
Rounding differences			$ (64)
Total change in revenues			$ 52,028

(1) Prices shown are realized, unhedged $/Bbl for oil and are realized, unhedged $/Mcf for natural gas.

(2) Production volumes are presented in MBbls for oil and in MMcf for natural gas.

Lease operating expenses. Lease operating expenses, which include workover expenses, increased to $30.6 million for the six months ended June 30, 2012 from $18.1 million for the six months ended June 30, 2011, an increase of approximately 69%. The increase was primarily due to an increase in drilling activity, which resulted in additional producing wells during the first six months of 2012 compared to the same period in 2011. The increase in well count also led to increases in routine repairs and maintenance. Additionally, a portion of the increase is due to approximately $1.1 million in additional workover expenses incurred during the first six months of 2012 as compared to the same period in 2011 resulting largely from costs incurred for the workover of one well. This workover is not indicative of costs typically incurred for workovers and was fully completed in the first quarter of 2012.

On a per-BOE basis, lease operating expenses increased in total to $5.67 per BOE for the six months ended June 30, 2012 from $4.53 per BOE for the six months ended June 30, 2011. Excluding the one-time workover expense noted above, lease operating expense per BOE at June 30, 2012 was $5.44 per BOE.

Production and ad valorem taxes. Production and ad valorem taxes increased to approximately $16.2 million for the six months ended June 30, 2012 from $15.0 million for the six months ended June 30, 2011, an increase of 8%. This increase was primarily due to the

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significant increase in production of approximately 1,409 MBOE, or 35%, for the first six months of 2012 as compared to the same period in 2011.

Drilling and production. Drilling and production costs increased to approximately $1.8 million for the six months ended June 30, 2012 from $0.7 million for the six months ended June 30, 2011 as a result of increased maintenance costs related to the increase in drilling during the first six months of 2012 as compared to the same period in 2011.

General and administrative ("G&A"). G&A expense increased to approximately $31.9 million for the six months ended June 30, 2012 from $19.8 million for the six months ended June 30, 2011, an increase of $12.1 million, or 61%. Increases in salaries, benefits and bonuses accounted for approximately $6.3 million of the increase due to the payment of performance bonuses totaling $2.0 million in February 2012 as well as an increase in the number of employees as we continue to grow our business.

Additionally, stock-based compensation increased by approximately $4.0 million to $4.8 million for the first six months of 2012 as compared to the same period in 2011 due to the issuance of 776,711 restricted stock awards and 602,948 non-qualified stock options during 2012. The fair value of the restricted stock awards issued during the first and second quarters of 2012 was calculated based on the value of our stock price on the date of grant in accordance with Generally Accepted Accounting Principles in the United States of America ("GAAP") and is being recognized on a straight-line basis over the three year requisite service period of the awards. The fair value of our non-qualified restricted stock options was determined using a Black-Scholes valuation model in accordance with applicable GAAP accounting and is being recognized on a straight-line basis over the four year requisite service period of the awards. 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 $1.0 million of the total change for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011.

On a per-BOE basis, G&A expense increased to $5.91 per BOE during the six months ended June 30, 2012 from $4.95 per BOE for the six months ended June 30, 2011. Excluding non-cash, stock-based compensation, G&A expense per BOE was $5.02 and $4.73 for the six months ended June 30, 2012 and 2011, respectively.

See Notes B and D to our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding our stock and performance based compensation.

Depreciation, depletion and amortization ("DD&A"). DD&A increased to approximately $112.2 million for the six months ended June 30, 2012 from $75.9 million for the six months

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ended June 30, 2011, an increase of $36.3 million, or 48%. The following table provides components of our DD&A expense for the six months ended June 30, 2012 and 2011.

		Six months ended June 30,		
(in thousands except for per BOE data)		**2012**		**2011**
Depletion of proved oil and natural gas properties	$	109,178	$	73,670
Depreciation of pipeline assets		1,505		1,151
Depreciation of other property and equipment		1,537		1,096
Total DD&A	$	112,220	$	75,917
Depletion of proved oil and natural gas properties per BOE	$	20.20	$	18.44
DD&A per BOE	$	20.77	$	19.00

The increase in depletion of proved oil and natural gas properties of $35.5 million and the increase in the depletion rate of $1.76 per BOE resulted primarily from (i) increased net book value on new reserves added, (ii) higher total production levels and (iii) increased capitalized costs for new wells completed in 2012.

Impairment expense. Impairment expense decreased to zero for the six months ended June 30, 2012 from $0.2 million for the six months ended June 30, 2011. Impairment expense incurred in the first six months of 2011 was to reflect our materials and supplies inventory at the lower of cost or market value calculated as of June 30, 2011. It was determined at June 30, 2012 that a lower of cost or market value 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 the estimated fair value. At June 30, 2012 and 2011, it was determined that our oil and natural gas properties were not impaired.

Commodity derivative financial instruments. Due to the inherent volatility in oil and natural gas prices, we use commodity derivative instruments, including puts, swaps, collars and basis swaps to hedge price risk associated with a significant portion of our anticipated oil and natural gas production. At each period end, we estimate the fair value of our commodity derivatives using a valuation prepared by an independent third party and recognize an unrealized gain or loss. We have not elected hedge accounting on these derivatives, and therefore, the unrealized gains and losses on open positions are reflected in current earnings. For the six months ended June 30, 2012 and 2011, our commodity derivatives resulted in a realized gain of $13.8 million and a realized loss of $0.9 million, respectively. For the six months ended June 30, 2012 and 2011, our commodity derivatives resulted in an unrealized gain of $15.3 million and an unrealized loss of $8.7 million, respectively. At June 30, 2012, we had 18 commodity derivatives contracts with associated deferred premiums totaling approximately $27.5 million. The estimated fair value of our total deferred premiums was approximately $23.6 million at June 30, 2012. The fair market value of these premiums is deducted from our unrealized gain or loss at each period end.

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Interest expense and realized and unrealized gains and losses on interest rate swaps. Interest expense increased to approximately $36.4 million for the six months ended June 30, 2012 from $22.3 million for the six months ended June 30, 2011, largely due to the issuance of our $350.0 million and $200.0 million 2019 senior unsecured notes in January 2011 and October of 2011, respectively, as well as the issuance of our $500.0 million 2022 senior unsecured notes in April of 2012 as shown in the table below.

(in thousands except for percentages)	Six months ended June 30, 2012 Weighted average principal	Six months ended June 30, 2012 Weighted average interest rate(3)	Six months ended June 30, 2011 Weighted average principal	Six months ended June 30, 2011 Weighted average interest rate(3)
Senior secured credit facility	$ 190,085	0.72%	$ 68,056	0.75%
2019 senior unsecured notes	550,000	4.73%	350,000	4.19%
2022 senior unsecured notes	500,000	1.29%		
Term loan(1)			100,000	0.31%
Broad Oak credit facility(2)			122,904	3.07%

(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.

(3) Interest rates presented are annual rates which have been prorated to reflect the portion of the year for which they have been incurred.

We have entered into certain variable-to-fixed interest rate swaps that hedge our exposure to interest rate variations on our variable interest rate debt. At June 30, 2012, we had interest rate swaps outstanding for a notional amount of $100.0 million with fixed pay rates ranging from 1.11% to 3.00% and terms expiring through September 2013. At June 30, 2011, we had interest rate swaps 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. We realized losses on interest rate swaps of $1.9 million and $2.6 million for the six months ended June 30, 2012 and 2011, respectively. Additionally, we recorded unrealized gains on interest rate swaps of $1.6 million and $1.5 million for the six months ended June 30, 2012 and June 30, 2011, respectively. At June 30, 2012, the estimated fair value of our interest rate swaps was in a net liability position of $0.4 million compared to a net liability position of $2.0 million at December 31, 2011.

Income tax expense. We recorded a deferred income tax expense of $32.2 million for the six months ended June 30, 2012, compared to a deferred income tax expense of $25.7 million for the six months ended June 30, 2011. The estimated annual effective tax rate was 36% for each of the six months ended June 30, 2012 and 2011. 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.

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Year ended December 31, 2011 as compared to the year ended December 31, 2010

The following table sets forth selected operating data for the year ended December 31, 2011 compared to the year ended December 31, 2010:

	Years ended December 31,	
(in thousands)	**2011**	**2010**
Operating results:		
Revenues		
Oil	$ 306,481	$ 126,891
Natural gas	199,774	112,892
Natural gas transportation and treating	4,015	2,217
Total revenues	510,270	242,000
Costs and expenses		
Lease operating expenses	43,306	21,684
Production and ad valorem taxes	31,982	15,699
Natural gas transportation and treating	977	2,501
Drilling and production	3,817	340
General and administrative (including non-cash stock-based compensation of $6,111 and $1,257 for the years ended December 31, 2011 and 2010, respectively)	51,064	30,908
Accretion of asset retirement obligations	616	475
Depreciation, depletion and amortization	176,366	97,411
Impairment expense	243	
Total costs and expenses	308,371	169,018
Non-operating income (expense):		
Realized and unrealized gain (loss):		
Commodity derivative financial instruments, net	21,047	11,190
Interest rate derivatives, net	(1,311)	(5,375)
Interest expense	(50,580)	(18,482)
Interest and other income	108	151
Write-off of deferred loan costs	(6,195)	
Loss on disposal of assets	(40)	(30)
Non-operating expense, net	(36,971)	(12,546)
Income tax expense	(59,374)	25,812
Net income	$ 105,554	$ 86,248

Oil and gas revenues. Our oil and gas revenues increased by approximately $266.5 million, or 111%, to $506.3 million during the year ended December 31, 2011 as compared to the year ended December 31, 2010. Our revenues are a function of oil and gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 9,431 BOE/D during the year ended December 31, 2011 as compared to the same period in 2010. The total increase in revenue of approximately $266.5 million is largely attributable to higher oil and gas production volumes as well as an increase in oil prices being realized for the year ended December 31, 2011 as compared to the year ended December 31, 2010. Production increased by 1,720 MBbls for oil and 10,330 MMcf for gas for the year ended December 31,

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2011 as compared to the year ended December 31, 2010. The net dollar effect of the increase in prices of approximately $79.5 million (calculated as the change in year-to-year average prices times current year production volumes for oil and gas) and the net dollar effect of the change in production of approximately $187.0 million (calculated as the increase in year-to-year volumes for oil and gas times the prior year average prices) are shown below.

	Change in prices(1)	Production volumes at December 31, 2011(2)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 14.00	3,368	$ 47,152
Natural gas	$ 1.02	31,711	$ 32,345
Total revenues due to change in price			$ 79,497

	Change in production volumes(2)	Prices at December 31, 2010(1)	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	1,720	$ 77.00	$ 132,440
Natural gas	10,330	$ 5.28	$ 54,542
Total revenues due to change in volume			$ 186,982
Rounding differences			$ (7)
Total change in revenues			$ 266,472

(1) Prices shown are realized, unhedged $/Bbl for oil and are realized, unhedged $/Mcf for natural gas.

(2) Production volumes are presented in MBbls for oil and in MMcf for natural gas.

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

Lease operating expenses. Lease operating expenses, which include workover expenses, increased to $43.3 million for the year ended December 31, 2011 from $21.7 million for the year ended December 31, 2010, an increase of approximately 100%. 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 gas became more favorable.

Production and ad valorem taxes. 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

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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 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 increased to approximately $51.1 million at December 31, 2011 from $30.9 million at December 31, 2010, an increase of $20.2 million, or 65%. Increases in professional fees incurred relating to the issuance of the 2019 senior unsecured notes, the Broad Oak acquisition, the filing of a registration statement relating to the 2019 senior unsecured notes with the SEC and other matters accounted for approximately $7.4 million, or 37%, 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.

Equity and 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.

On a per-BOE basis, G&A expense decreased to $5.90 per BOE during the year ended December 31, 2011 from $5.93 per BOE during the year ended 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.

We have a 2011 Omnibus Equity Incentive Plan, which allows for the issuance of restricted stock awards, stock options and performance units to current and prospective directors, officers, employees, consultants and advisors. There were no issuances under the plan of restricted stock awards, stock options or performance units during the year ended December 31, 2011. In February 2012, we issued 593,939 restricted stock awards, 602,948 stock options and 49,244 performance units to employees and officers and will record compensation expense related to these issuances in accordance with GAAP in future periods. See Note O to our audited consolidated financial statements included elsewhere in this prospectus for additional information.

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Depreciation, depletion and amortization ("DD&A"). DD&A increased to approximately $176.4 million at December 31, 2011 from $97.4 million at December 31, 2010, an increase of $79.0 million, or 81%. The following table provides components of our DD&A expense for the years ended December 31, 2011 and 2010.

	Years ended December 31,	
(in thousands except for per BOE data)	**2011**	**2010**
Depletion of proved oil and natural gas properties	$ 171,517	$ 93,815
Depreciation of pipeline assets	2,466	1,982
Depreciation of other property and equipment	2,383	1,614
Total depletion, depreciation and amortization	$ 176,366	$ 97,411
Depletion of proved oil and natural gas properties per BOE	$ 19.82	$ 18.00
DD&A per BOE	$ 20.38	$ 18.69

The increase in depletion of proved oil and natural gas properties of $77.7 million and the increase in the depletion rate of $1.82 per BOE resulted primarily from (i) increased net book value on new reserves added, (ii) higher total production levels, (iii) increased capitalized costs for new wells completed in 2011 and (iv) a corresponding offset caused by the increase in oil and natural gas prices between periods used to calculate proved reserves.

The increase in depreciation for pipeline and gas gathering assets of $0.5 million was primarily due to the expansion of our gas gathering system.

The increase in depreciation for other fixed assets of $0.8 million was primarily due to an increase in fixed asset additions as we continued to grow our business.

Impairment expense. Impairment expense increased to $0.2 million for the year ended December 31, 2011 from zero for the year ended December 31, 2010. This increase is due to a write-down of our materials and supplies inventory to reflect the balance at the lower of cost or market value calculated as of December 31, 2011. It was determined at December 31, 2010 that a lower of cost or market adjustment was not needed for materials and supplies.

We evaluate the impairment of our oil and 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 gas properties to the calculated full cost ceiling amount, which is determined to be their estimated fair value. For the years ended December 31, 2011 and 2010, it was determined that our oil and gas properties were not impaired.

Commodity derivative financial instruments. Due to the inherent volatility in oil and gas prices, we use commodity derivative instruments, including puts, swaps, collars and basis swaps to hedge price risk associated with a significant portion of our anticipated oil and gas production. At each period end, we estimate the fair value of our commodity derivatives and recognize an unrealized gain or loss. We have not elected hedge accounting on these derivatives, and therefore, the unrealized gains and losses on open positions are reflected in current earnings. For the years ended December 31, 2011 and 2010, our commodity derivatives resulted in realized gains of $3.7 million and $22.7 million, respectively. For the years ended December 31, 2011 and 2010, our commodity derivatives resulted in an unrealized gain of

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$17.3 million and an unrealized loss of $11.5 million, respectively. During the fourth quarter ended December 31, 2009 and the years ended December 31, 2010 and 2011, we entered into a number of new commodity derivatives of which twelve had associated deferred premiums totaling approximately $19.8 million. The estimated fair value of our total deferred premiums was approximately $18.9 million at December 31, 2011. The fair market value of these premiums is deducted from our unrealized gains at December 31, 2011. The overall gain at December 31, 2011 is largely due to the decrease in market prices to levels lower than those specified in our fixed price commodity derivative contracts during the year ended December 31, 2011.

Interest expense and realized and unrealized gains and losses on interest rate swaps. Interest expense increased to approximately $50.6 million for the year ended December 31, 2011 from $18.5 million for the year ended December 31, 2010, largely due to higher weighted average interest rates and higher weighted average outstanding debt balances on our senior secured credit facility and due to the issuance of the 2019 senior unsecured notes during 2011 as compared to 2010 as shown in the table below. Additionally, we had approximately $3.5 million in amortized deferred loan costs and $0.7 million in other fees and deferred option premium amortization that were charged to interest expense for the year ended December 31, 2011 as compared to $2.0 million in amortized deferred loan costs and $0.4 million in other fees and deferred option premium amortization for the year ended December 31, 2010.

(in thousands except for percentages)	Year ended December 31, 2011		Year ended December 31, 2010	
	Weighted average principal	Weighted average interest rate	Weighted average principal	Weighted average interest rate
Senior secured credit facility	$299,502	2.07%	$180,788	3.38%
2019 senior unsecured notes	392,319	8.98%		
Term loan(1)	100,000	0.51%	100,000	4.49%
Broad Oak credit facility(2)	122,904	3.07%	123,782	4.27%

(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.

During 2010, we entered into certain variable-to-fixed interest rate swaps that hedge our exposure to interest rate variations on our variable interest rate debt. At December 31, 2011, we had interest rate swaps 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. At December 31, 2010, we had interest rate swaps outstanding for a notional amount of $300.0 million with fixed pay rates ranging from 1.11% to 3.41% and terms expiring through September 2013. We realized losses on interest rate swaps of $4.9 million and $5.2 million for the years ended December 31, 2011 and 2010, respectively. Additionally, we recorded an unrealized gain on interest rate swaps of $3.6 million as of December 31, 2011 compared to an unrealized loss of $0.1 million at December 31, 2010. At December 31, 2011, the estimated fair value of our interest rate swaps was in a net liability position of $2.0 million compared to a net liability position of $5.5 million at December 31, 2010.

Write-off of deferred loan costs. In January 2011, we used a portion of the net proceeds from the issuance of the 2019 senior unsecured notes to pay in full and retire our term loan. Additionally, concurrent with the issuance of the 2019 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

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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, 2011, the borrowing base on our senior secured credit facility is $712.5 million. On July 1, 2011, in connection 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 prepared separate tax returns for Laredo Petroleum, LLC, Laredo Petroleum, Inc. and Broad Oak for the period prior to July 1, 2011. We recorded a deferred income tax expense of $59.4 million for the year ended December 31, 2011, compared to a deferred income tax benefit of $25.8 million for the year ended December 31, 2010. The estimated annual effective tax rates were 36% and 37% for the years ended December 31, 2011 and 2010, respectively; however, 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.

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Year ended December 31, 2010 as compared to year ended December 31, 2009

The following table sets forth selected operating data for the year ended December 31, 2010 compared to the year ended December 31, 2009:

	Years ended December 31,	
(in thousands)	**2010**	**2009**
Operating results:		
Revenues		
Oil	$ 126,891	$ 29,946
Natural gas	112,892	64,401
Natural gas transportation and treating	2,217	2,227
Total revenues	242,000	96,574
Costs and expenses		
Lease operating expenses	21,684	12,531
Production and ad valorem taxes	15,699	6,129
Natural gas transportation and treating	2,501	1,416
Drilling rig fees		1,606
Drilling and production	340	758
General and administrative (including non-cash stock-based compensation of $1,257 and $1,419 for the years ended December 31, 2010 and 2009, respectively)	30,908	22,583
Accretion of asset retirement obligations	475	406
Depreciation, depletion and amortization	97,411	58,005
Impairment expense		246,669
Total costs and expenses	169,018	350,103
Non-operating income (expense):		
Realized and unrealized gain (loss):		
Commodity derivative financial instruments, net	11,190	5,744
Interest rate derivatives, net	(5,375)	(3,394)
Interest expense	(18,482)	(7,464)
Interest and other income	151	227
Loss on disposal of assets	(30)	(85)
Non-operating expense, net	(12,546)	(4,972)
Income tax benefit	25,812	74,006
Net income (loss)	$ 86,248	$ (184,495)

Oil and gas revenues. Our oil and gas revenues increased by approximately $145.4 million, or 154%, to approximately $239.8 million during the year ended December 31, 2010 as compared to the year ended December 31, 2009. Our revenues are a function of oil and gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 4,516 BOE/D during the year ended December 31, 2010 as compared to the year ended December 31, 2009. The total increase in revenue of approximately $145.4 million is largely attributable to an increase in oil and gas production volumes as well as an increase in oil and gas prices realized for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Production increased by 1,135 MBbls for oil and by 3,079 MMcf for

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gas during 2010 as compared to 2009. The net dollar effect of the increase in prices of approximately $68.3 million (calculated as the change in year-to-year average prices times current year production volumes for oil and gas) and the net dollar effect of the change in production of approximately $77.1 million (calculated as the change in year-to-year volumes for oil and gas times the prior year average prices) are shown below.

	Change in prices(1)	Production volumes at December 31, 2010(2)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 18.63	1,648	$ 30,702
Natural gas	$ 1.76	21,381	$ 37,631
Total revenues due to change in price			$ 68,333

	Change in production volumes(2)	Prices at December 31, 2009(1)	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	1,135	$ 58.37	$ 66,250
Natural gas	3,079	$ 3.52	$ 10,838
Total revenues due to change in volumes			$ 77,088
Rounding differences			$ 15
Total change in revenues			$ 145,436

(1) Prices shown are realized, unhedged $/Bbl for oil and are realized, unhedged $/Mcf for gas.

(2) Production volumes are presented in MBbls for oil and in MMcf for natural gas.

Lease operating expenses. Lease operating expenses increased to approximately $21.7 million for the year ended December 31, 2010 from $12.5 million for the year ended December 31, 2009, an increase of 74%, primarily due to the increase in the number of owned properties during 2010 as compared to 2009. On a per-BOE basis, lease operating expenses increased in total to $4.16 per BOE at December 31, 2010 from $3.52 per BOE at December 31, 2009. This increase was largely a result of lower production for the first nine months of 2010 as we scaled back our drilling program in response to lower oil and gas prices, while continuing to incur lease operating expenses on properties with normal declining production.

Production and ad valorem taxes. Production and ad valorem taxes increased to approximately $15.7 million for the year ended December 31, 2010 from $6.1 million for the year ended December 31, 2009, an increase of $9.6 million, or 157%, primarily due to the increase in market prices (not including the effects of hedging) for 2010 as compared to 2009. The average realized prices excluding derivatives for the year ended December 31, 2010 were $77.00 per Bbl for oil and $5.28 per Mcf for natural gas as compared to $58.37 per Bbl for oil and $3.52 per Mcf for natural gas for the year ended December 31, 2009.

Drilling rig fees. We have committed to several short-term drilling contracts with various third parties to complete our drilling projects. The contracts contain an early termination clause that requires us to pay significant penalties to the third parties if we cease drilling efforts. For the

year ended December 31, 2009, we incurred approximately $1.6 million in stacked rig fees. In 2010, we did not incur any stacked rig fees related to our drilling rig contracts.

Drilling and production. Drilling and production costs decreased to approximately $0.3 million at December 31, 2010 from $0.8 million at December 31, 2009 as a result of improved cost control measures related to our activities.

General and administrative ("G&A"). G&A expense increased to approximately $30.9 million at December 31, 2010 from $22.6 million at December 31, 2009, an increase of $8.3 million, or 37%. Increases in salaries, benefits and bonus expense (net of capitalized salary and benefits) accounted for approximately $5.4 million, or 64%, of the change in G&A expense as we continued to grow our employee base during 2010. Equity and stock-based compensation decreased to approximately $1.3 million at December 31, 2010 from $1.4 million at December 31, 2009 due largely to a lower average grant date fair value and number of awards granted and vested during 2010 as compared to 2009. The remainder of the increase largely consisted of additional expenditures for technology, travel costs and professional fees.

On a per-BOE basis, G&A expense decreased to $5.93 per BOE during the year ended December 31, 2010 from $6.34 per BOE at December 31, 2009. This decrease was a result of a larger overall increase in production volumes between the two periods.

Depreciation, depletion and amortization ("DD&A"). DD&A increased to approximately $97.4 million at December 31, 2010 from $58.0 million at December 31, 2009, an increase of $39.4 million, or 68%. The following table provides components of our DD&A expense for the years ended December 31, 2010 and 2009.

	Years ended December 31,	
	2010	**2009**
Depletion of proved oil and natural gas properties	$ 93,815	$ 55,399
Depreciation of pipeline assets	1,982	1,461
Depreciation of other property and equipment	1,614	1,145
Total depletion, depreciation and amortization	$ 97,411	$ 58,005
Depletion of proved oil and natural gas properties per BOE	$ 18.00	$ 15.54
DD&A per BOE	$ 18.69	$ 16.28

The increase in depletion of proved oil and natural gas properties of approximately $38.4 million and the increase in the depletion rate of $2.46 per BOE were due largely to additions to the full cost pool related to our increase in drilling in 2011 as compared to 2010.

The increase in depreciation for pipeline and gas gathering assets of approximately $0.5 million was primarily due to the expansion of our gas gathering system.

The increase in depreciation for other fixed assets of approximately $0.5 million was primarily due to an increase in fixed asset additions as we grew the company.

Impairment expense. We evaluate the impairment of our oil and 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 gas properties to the calculated full cost ceiling amount, which is determined to be their estimated fair value.

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Impairment expense at December 31, 2009 reflects the impairment of our oil and gas properties of approximately $245.9 million due to declining market prices for oil and gas, and the write-down to lower of cost of market of our materials and supplies of approximately $0.8 million, consisting of pipe and well equipment, due to declining market prices. For oil and natural gas assets, the full cost ceiling calculation was computed using the unweighted arithmetic average first-day-of-the-month prices for the 12-months ended December 31, 2009 of $57.04 per Bbl for oil and $3.15 per MMBtu for natural gas, adjusted for energy content, transportation fees and regional price differentials. It was determined that oil and natural gas properties were not impaired for the year ended December 31, 2010 as their carrying amount did not exceed the calculated full cost ceiling. Additionally, a write-down of our materials and supplies was not necessary at December 31, 2010 based on our lower of cost or market analysis.

Commodity derivative financial instruments. Due to the inherent volatility in oil and gas prices, we use commodity derivative instruments including puts, swaps, collars, and basis swaps to hedge future price risk associated with a significant portion of our anticipated oil and gas production. At each period end, we estimate the fair value of our commodity derivatives and recognize an unrealized gain or loss. We have not elected hedge accounting on these derivatives, therefore, the unrealized gains and losses on open positions are reflected in current earnings. For the years ended December 31, 2010 and 2009, our hedges resulted in realized gains of approximately $22.7 million and $52.1 million, respectively. For the years ended December 31, 2010 and 2009, our hedges resulted in unrealized losses of approximately $11.5 million and $46.4 million, respectively. During 2009, some of our hedge contracts matured and commodity prices began to recover, creating an unrealized loss at December 31, 2009. During 2010, we entered into a number of new commodity derivatives of which seven had associated deferred premiums totaling approximately $13.4 million. The estimated fair value of our total deferred premiums was approximately $12.5 million at December 31, 2010. The fair market value of these premiums is deducted from our unrealized gains and losses and largely accounts for the overall unrealized loss on commodity derivatives at December 31, 2010.

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense increased to approximately $18.5 million for the year ended December 31, 2010 from $7.5 million for the year ended December 31, 2009, largely due to a higher weighted average interest rate and a higher weighted average outstanding debt balance on the Broad Oak credit facility and the issuance of our term loan during 2010 as compared to 2009. Additionally, we had approximately $2.0 million in amortized deferred loan costs and $0.4 million in other fees and deferred premium amortization that were charged to interest expense for the year ended December 31, 2010 as compared to $0.6 million in amortized deferred loan costs and an insignificant amount of other fees and amortization for the year ended December 31, 2009.

	Year ended December 31, 2010		**Year ended December 31, 2009**	
(in thousands except for percentages)	**Weighted average principal**	**Weighted average interest rate**	**Weighted average principal**	**Weighted average interest rate**
Senior secured credit facility	$180,788	3.38%	$154,011	3.67%
Term loan(1)	100,000	4.49%		
Broad Oak credit facility(2)	123,782	4.27%	27,657	4.65%

(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.

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During 2010 and 2009, we 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, 2010, we had interest rate swaps and caps outstanding for a notional amount of $300.0 million with fixed pay rates ranging from 1.11% to 3.41% and terms expiring from June 2011 to September 2013 compared to outstanding swaps for a notional amount of $180.0 million with fixed pay rates ranging from 1.60% to 3.41% and terms expiring from June 2011 to June 2012 at December 31, 2009. During the year ended December 31, 2010, we realized a loss on interest rate derivatives of approximately $5.2 million compared to a realized loss of $3.8 million for the year ended December 31, 2009. Additionally, we recorded an unrealized loss on interest rate derivatives of approximately $0.1 million as of December 31, 2010 compared to an unrealized gain of $0.4 million at December 31, 2009. At December 31, 2010, the estimated fair value of our interest rate derivatives was in a net liability position of approximately $5.5 million compared to a net liability position of $5.6 million at December 31, 2009.

Income tax expense. We recorded a deferred income tax benefit of approximately $25.8 million for the year ended December 31, 2010, compared to a deferred income tax benefit of approximately $74.0 million for the year ended December 31, 2009. At December 31, 2009, we recognized a deferred income tax benefit for the impairment of our oil and gas properties of approximately $86.1 million.

Additionally, we recorded a valuation allowance of approximately $0.7 million against our Texas deferred tax asset at December 31, 2010, as we believe it is more likely than not that we will not realize a future benefit for the full amount of our Texas deferred tax asset. The estimated annual effective tax rate was 37% for the year ended December 31, 2010 and 35% for the year ended December 31, 2009. Our annual 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.

During the fourth quarter of 2010, we determined that it was more likely than not that the remaining federal net operating loss carry-forwards and net federal deferred assets would be realized. Consideration given included estimated future net cash flows from oil and gas reserves (including the timing of those cash flows) and the future tax effect of the deferred tax assets and liabilities recorded at December 31, 2010. As a result of this determination, the valuation allowance was released against the deferred tax assets, resulting in a decrease of the valuation allowance by approximately $47.9 million.

For the year ended December 31, 2009, we increased the valuation allowance against Broad Oak's net federal deferred tax asset by approximately $16.5 million and decreased the valuation allowance against Broad Oak's Louisiana deferred tax by approximately $0.1 million. We believed it was more likely than not that we would not realize a future benefit for the full amount of the federal and Louisiana net deferred tax asset as of December 31, 2009.

Liquidity and capital resources

Our primary sources of liquidity have been capital contributions from Warburg Pincus, certain members of our management and our board of directors, borrowings on our senior secured credit facility, proceeds from the 2019 senior unsecured notes and the 2022 senior unsecured notes, borrowings on the prior Broad Oak credit facility, borrowings on our prior term loan

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facility, proceeds from our IPO and cash flows from operations. Our primary use of capital has been for the exploration, development and acquisition of oil and gas properties. 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 significant 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 2014 even with the general decline in the prices of natural gas.

At June 30, 2012, we had no debt outstanding and approximately $0.03 million of outstanding letters of credit on our senior secured credit facility. Additionally, we had $1.05 billion of outstanding senior unsecured notes, excluding the remaining premium of $1.9 million received on the October 2011 offering of our 2019 senior unsecured notes. We had approximately $785.0 million available for borrowings on our senior secured credit facility and $146.5 million in cash on hand for total available liquidity of approximately $931.5 million at June 30, 2012. We believe such availability as well as cash flows from operations provide us with the ability to implement our planned exploration and development activities.

As of September 30, 2012, we had approximately $50.0 million in outstanding borrowings on our senior secured credit facility and approximately $735.0 million available for borrowings.

We expect that, in the future, our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite potential declines in the price of oil and gas. Please see " Quantitative and qualitative disclosures about market risk" below.

Cash flows

Our cash flows for the six months ended June 30, 2012 and 2011 and the years ended December 31, 2011, 2010 and 2009 are as follows:

	Six months ended June 30,		Years ended December 31,		
(in thousands)	**2012**	**2011**	**2011**	**2010**	**2009**
Net cash provided by operating activities	$ 199,790	$ 162,058	$ 344,076	$ 157,043	$ 112,669
Net cash used in investing activities	(485,831)	(359,449)	(706,787)	(460,547)	(361,333)
Net cash provided by financing activities	404,524	188,208	359,478	319,752	250,139
Net increase (decrease) in cash	$ 118,483	$ (9,183)	$ (3,233)	$ 16,248	$ 1,475

Cash flows provided by operating activities

Net cash provided by operating activities was $199.8 million and $162.1 million for the six months ended June 30, 2012 and 2011, respectively. The increase of $37.7 million was largely due to increases in revenue due to increased production.

Net cash provided by operating activities was $344.1 million, $157.0 million and $112.7 million for the years ended December 31, 2011, 2010 and 2009, respectively. The increases of

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$187.1 million from 2010 to 2011 and $44.3 million from 2009 to 2010 were largely due to significant increases in revenue due to our successful drilling program, as well as an increase in the market price for oil.

Our operating cash flows are sensitive to a number of variables, the most significant of which are production levels and the volatility of oil and 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 " Quantitative and qualitative disclosures about market risk."

Cash flows used in investing activities

We used cash flows in investing activities of approximately $485.8 million and $359.4 million for the six months ended June 30, 2012 and 2011, respectively, which is an increase of $126.4 million. A portion of our capital expenditures for the six months ended June 30, 2012 reflects expenditures which were accrued for at December 31, 2011 as part of our 2011 capital budget, but due to the timing of when billings were received, were paid during the first quarter of 2012. Additionally, a significant portion of the increase was due to increasing our drilling efforts in our Permian Basin and Anadarko Granite Wash areas as we continue to explore and develop our identified potential drilling locations.

We used cash flows in investing activities of approximately $706.8 million, $460.5 million and $361.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. The increases of $246.3 million from 2010 to 2011 and $99.2 million from 2009 to 2010 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 and improving commodity prices.

Our cash used in investing activities for capital expenditures for the six months ended June 30, 2012 and 2011 and the years ended December 31, 2011, 2010 and 2009 is summarized in the table below.

	Six months ended June 30,		Years ended December 31,		
(in thousands)	**2012**	**2011**	**2011**	**2010**	**2009**
Restricted cash	$	$	$	$	$ 2,201
Capital expenditures:					
Oil and gas properties	(473,846)	(348,523)	(687,062)	(454,161)	(340,636)
Pipeline and gathering assets	(7,031)	(6,344)	(13,368)	(4,277)	(19,995)
Other fixed assets	(4,988)	(4,602)	(6,413)	(2,198)	(3,071)
Proceeds from other asset disposals	34	20	56	89	168
Net cash used in investing activities	$ (485,831)	$ (359,449)	$ (706,787)	$ (460,547)	$ (361,333)

Capital expenditure budget

Our board of directors approved a budget of approximately $900 million for calendar year 2012, excluding acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

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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 $404.5 million and $188.2 million for the six months ended June 30, 2012 and 2011, respectively.

The increase in net cash provided by financing activities for the six months ended June 30, 2012 is the result of issuing our 2022 senior unsecured notes in an aggregate principal amount of $500 million in April 2012, which were offset by payments for loan costs totaling $10.5 million, as well as the net effect of payments and borrowings on our senior secured credit facility.

Net cash provided by financing activities for the six months ended June 30, 2011 was largely the result of our first issuance of 2019 senior unsecured notes in an aggregate principal amount of $350.0 million in January 2011 as well as net borrowings and payments on the former Broad Oak credit facility and our senior secured credit facility and the payment-in-full and termination of our $100.0 million term loan. Additionally, we incurred $10.6 million in loan costs for the six months ended June 30, 2011.

We had cash flows provided by financing activities of $359.5 million, $319.8 million and $250.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Net cash provided by financing activities for the year ended December 31, 2011 was primarily the result of $552.0 million in gross proceeds from the issuance of the 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.

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For the year ended December 31, 2009, net cash from financing activities was primarily the result of capital contributions from Warburg Pincus, certain members of our management and our independent directors of approximately $154.6 million, borrowings on our senior secured credit facility of $75.0 million and net borrowings of approximately $23.5 million on the Broad Oak credit facility.

Debt

At June 30, 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 connection with the Broad Oak acquisition. Our term loan facility was paid in full and retired in connection with the closing of the January 2011 offering of the 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 a borrowing base of $785.0 million. Our senior secured credit facility will mature on July 1, 2016.

We have a choice of borrowing at an Adjusted Base Rate or in Eurodollars. Adjusted Base Rate loans bear interest at the Adjusted Base Rate plus an applicable margin between 0.75% and 1.75%, and Eurodollar loans bear interest at the adjusted London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.75% and 2.75%. At June 30, 2012, the applicable margin rates were 0.75% for the Adjusted Base Rate advances and 1.75% for the Eurodollar advances. We had no outstanding borrowings on our senior secured credit facility at June 30, 2012. We are also required to pay an annual commitment fee on the unused portion of the bank's commitment of 0.5%.

Our senior secured credit facility is secured by a first priority lien on our assets (including the stock of Laredo Petroleum Holdings, Inc.'s wholly-owned subsidiary, 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 June 30, 2012, we were subject to and in compliance with 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 June 30, 2012 and December 31, 2011, 2010 and 2009. At September 30, 2009, we were in violation of our current ratio covenant. A covenant waiver was included in the fourth amended senior secured credit facility agreement dated November 5, 2009.

Our senior secured credit facility contains various covenants that limit our ability to:

- incur indebtedness;

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- 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 June 30, 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 June 30, 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;

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- 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 indenture 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. At June 30, 2012, we had one letter of credit outstanding totaling approximately $0.03 million under our senior secured credit facility.

Subsequent to June 30, 2012, we borrowed $50.0 million on our senior secured credit facility on August 28, 2012. As of September 30, 2012, the outstanding balance on our senior secured credit facility was $50.0 million.

Refer to Note C of our audited consolidated financial statements included elsewhere in this prospectus and Note C of our unaudited consolidated financial statements included elsewhere in this prospectus for further discussion of our senior secured credit facility.

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. The borrowing base was subject to a semi-annual redetermination. The Broad Oak credit facility term extended to April 11, 2013, at which time the outstanding balance would have been due. As defined in the Broad Oak credit facility, the Adjusted Base Rate Advances and Eurodollar Advances on 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 gas properties.

Concurrently with the Broad Oak acquisition on July 1, 2011, the Broad Oak credit facility was paid in full and terminated. Refer to Note A of our audited consolidated financial statements included elsewhere in this prospectus for further discussion of the Broad Oak transaction.

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As of December 31, 2010 and 2009, borrowings outstanding on the Broad Oak credit facility totaled approximately $214.1 million and $44.6 million, respectively.

Senior unsecured notes. On January 20, 2011 and October 19, 2011, Laredo Petroleum, Inc. completed the offerings of $350 million aggregate principal amount and $200 million aggregate principal amount, respectively, of $9^1/_2$% 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. The 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"). The 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 the 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 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. The 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 the $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

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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.

As of September 30, 2012, we had a total of $1.05 billion of senior unsecured notes outstanding. Refer to Note C of our audited consolidated financial statements and Note C of our unaudited consolidated financial statements included elsewhere in this prospectus for further discussion of the 2019 senior unsecured notes and the 2022 senior unsecured notes.

Obligations and commitments

At December 31, 2011, we had the following significant contractual obligations and commitments that will require capital resources:

					Payments due
(in thousands)	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**	**Total**
Senior secured credit facility(1)	$	$	$ 85,000	$	$ 85,000
Senior unsecured notes	52,250	104,500	104,500	680,625	941,875
Drilling rig commitments(2)	9,631				9,631
Derivative financial instruments(3)	6,218	13,215	240		19,673
Asset retirement obligations(4)	1,458	788	1,022	9,806	13,074
Office and equipment leases(5)	1,413	2,550	1,013		4,976
Total	$ 70,970	$ 121,053	$ 191,775	$ 690,431	$ 1,074,229

(1) Includes outstanding principal amount at December 31, 2011. 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 June 30, 2012, we had no outstanding borrowings on our senior secured credit facility due in 2016 as the balance was paid-in-full in April 2012 with the proceeds of the 2022 senior unsecured notes issuance.

(2) At December 31, 2011, we had several drilling rigs under term contracts which expire during 2012. 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 J to our audited consolidated financial statements included elsewhere in this prospectus for additional discussion of our drilling contract commitments. As of June 30, 2012, our drilling rig commitments total approximately $35.8 million due to increased drilling activity in our Permian and Anadarko Granite Wash regions and are due within one year.

(3) Represents payments due for deferred premiums on our commodity hedging contracts. As of June 30, 2012, our deferred premiums total approximately $27.5 million. Refer to Note H to our audited consolidated financial statements and Note G to our unaudited consolidated financial statements included elsewhere in this prospectus for additional discussion of our deferred hedging premiums.

(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. As of June 30, 2012, our asset retirement obligation totals approximately

$15.9 million. See Note B to our audited consolidated financial statements and to our unaudited consolidated financial statements included elsewhere in this prospectus for further discussion of our asset retirement obligation.

(5) See Note J to our audited consolidated financial statements and Note I to our unaudited consolidated financial statements included elsewhere in this prospectus for a description of our lease obligations.

In addition to the obligations and commitments noted above, as of June 30, 2012, our contractual obligations included an addition of approximately $6.2 million for the estimated total liability payable for our performance unit awards as of June 30, 2012, which will be payable in December 2014.

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Critical accounting policies and estimates

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

In management's opinion, the more significant reporting areas impacted by our judgments and estimates are the choice of accounting method for oil and natural gas activities, estimation of oil and natural gas reserve quantities and standardized measure of future net revenues, revenue recognition, impairment of oil and gas properties, asset retirement obligations, valuation of derivative financial instruments, valuation of stock-based compensation and performance unit compensation, and estimation of income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

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 gas industry. There are two allowable methods of accounting for oil and 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 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.

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

Our independent reserve engineers prepare the estimates of oil and gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil and 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 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 gas properties

We review the carrying value of our oil and 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 year ended December 31, 2009, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from our proved reserves, net of related income tax considerations, resulting in a write-down in the carrying value of oil and gas properties of $245.9 million. For the six months ended June 30, 2012 and the years ended December 31, 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, effective December 31, 2009, current prices are calculated as the average oil and 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.

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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 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 "Non-operating income (expense)" in our consolidated statements of operations.

Stock-based compensation

Under the modified prospective accounting approach, 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 to our audited consolidated financial statements and our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding our equity and stock-based compensation.

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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.

Income taxes

At June 30, 2012 and December 31, 2011, 2010 and 2009, we had deferred tax assets of $64.9 million, $95.6 million, $155.0 million and $129.1 million, respectively. At December 31, 2009, our deferred tax asset included a valuation allowance of approximately $48.6 million, of which $47.9 million was subsequently reversed in the fourth quarter of 2010.

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 carryforwards 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

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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 carryforward deferred tax assets in future years;
- the existence of significant proved oil and 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 the first six months of 2012 and in 2011, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered that in both 2008 and 2009, we had net operating losses due to impairment expense recognized largely as a result of lower oil and natural gas prices experienced during the economic downturn, which led to a full cost ceiling impairment recognized in both 2008 and 2009. Additionally, we considered our strong earnings history exclusive of the loss that created the future temporary difference, and that while a full cost ceiling impairment is possible in the future, we do not believe the impairments recorded in 2008 and 2009 are indicative of future full cost impairments based on the following: (i) the book basis of our oil and gas assets at June 30, 2012 and December 31, 2011, (ii) the net basis differences in our oil and gas properties represented by a net deferred tax liability at June 30, 2012 and December 31, 2011, and (iii) our full cost ceiling cushion at June 30, 2012 and December 31, 2011. We believe it is proper and meaningful when analyzing the negative evidence of our historic three-year results to adjust for items that cannot be expected to occur on a similar basis during the future period allowed to recover the deferred tax asset, such as our full cost impairments noted above. We believe the adjusted three-year results provide less negative evidence than that presented by the unadjusted cumulative losses.

We also determined through our analysis that our net operating loss carryforward 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 as well as future market pricing as determined by the New York Mercantile Exchange. Based on our forecasted results from multiple analyses, at June 30, 2012, December 31, 2011 and 2010, future taxable income from our oil and gas reserves is expected to be sufficient to utilize the entire net operating loss carryforward in approximately six to eight 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. Based on this, we determined in the fourth quarter of 2010 that given the proper weight of the positive evidence noted above as compared to the negative evidence of our cumulative net losses, it was more-likely-than-not that our deferred tax asset would be recovered.

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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.

See Note B to our audited consolidated financial statements and our unaudited consolidated financial statements included elsewhere in this prospectus for a discussion of additional accounting policies and estimates made by management.

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 financial statements.

Inflation

Inflation in the United States 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, 2009 through the six months ended June 30, 2012. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the United States 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."

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 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

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market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity price exposure. For a discussion of how we use financial commodity put, collar, swap and basis swap contracts to mitigate some of the potential negative impact on our cash flow caused by changes in oil and gas prices, see " Hedging."

Interest rate risk. As part of our senior secured credit facility, we have debt which bears interest at a floating rate. At June 30, 2012, we had no indebtedness outstanding on our senior secured credit facility.

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 swap and cap agreements which hedge our exposure to interest rate variations on our senior secured credit facility. At June 30, 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 contracts (approximately $33.4 million at June 30, 2012), joint interest receivables (approximately $31.1 million at June 30, 2012) and the receivables from the sale of our oil and natural gas production (approximately $38.9 million at June 30, 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.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control who participates in our wells. Refer to Note I of our audited consolidated financial statements included elsewhere in this prospectus for additional disclosures regarding credit risk.

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Business

Overview

We are 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 June 30, 2012, we have assembled 188,014 net acres in the Permian Basin and 37,924 net acres in the Anadarko Granite Wash.

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 80 miles long (north/south) in Glasscock, Howard, Reagan and Sterling Counties, and is referred to in this prospectus as the "Permian-Garden City" area. As of June 30, 2012, we held 142,274 net acres in more than 300 sections in the Permian-Garden City area, with an average working interest of approximately 94% in all producing wells.

We believe our acreage in the Permian-Garden City area is a resource play for the Wolfberry interval, comprised of multiple producing formations, including the four identified shale zones targeted for horizontal drilling (Upper, Middle and Lower Wolfcamp and Cline shales). Through September 17, 2012, we have drilled and completed 49 horizontal wells in these four horizontal target zones. We have completed 33 horizontal Cline wells and 14 horizontal Upper Wolfcamp wells. Our recent horizontal activity has moved toward drilling longer laterals (up to 7,500 feet) and increased frac density (up to 28 stages) as we continue the optimization of our completion techniques. Through September 2012, we have completed nine horizontal Cline wells and ten horizontal Upper Wolfcamp wells which have at least 30 days of production history. The average 30-day IP per stage of fracture stimulation for the nine horizontal Cline wells is 31 BOE/D per stage. The average 30-day IP per stage of fracture stimulation for the ten horizontal Upper Wolfcamp wells is approximately 30 BOE/D per stage. Additionally, we have completed one horizontal well in each of the Middle and Lower Wolfcamp zones. The one Middle Wolfcamp well that we have completed has a 30-day IP per stage of fracture stimulation of 36 BOE/D. We are still drilling our second Middle Wolfcamp horizontal well. Our first horizontal Lower Wolfcamp well is producing oil but does not have 30 days of production. Based on our technical data and well performance, we believe we have to date confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 50% and 45%, respectively, of our Permian-Garden City acreage. Going forward, we plan to continue drilling and collecting technical data across our Permian-Garden City acreage, as reflected in our 2012 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 Granite Wash formation. The Granite

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Wash is a conventional play requiring 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 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 growth in reserves, production and cash flow.

Since our inception, we have rapidly grown our reserves, production and cash flow through both our drilling program and strategic acquisitions, as evidenced by our July 2011 acquisition of Broad Oak. Our net proved reserves were estimated at 156,453 MBOE as of December 31, 2011, of which 40% were classified as proved developed and 36% as oil. 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. Unless otherwise specifically identified in this prospectus, the information presented with respect to our estimated proved reserves has been prepared by Ryder Scott, our independent reserve engineers, in accordance with the rules and regulations of the SEC applicable to the periods presented.

Our net average daily production for the six months ended June 30, 2012 was 29,690 BOE/D, 41% of which was oil and 59% 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 and, to a lesser extent, liquids-rich opportunities in the Anadarko Granite Wash.

In 2012, more emphasis has been placed on our horizontal drilling program than in prior periods. Approximately 85% of our planned drilling capital for 2012 will be invested in the Permian Basin, and we are increasingly allocating it towards our horizontal drilling activity. As of September 17, 2012, we had completed 49 gross horizontal Wolfcamp and Cline shale wells in the Permian and 21 gross horizontal Granite Wash wells. The horizontal drilling program comprises an extensive, multi-year, multiple-zone inventory of exploratory and development opportunities.

We maintain a financial profile that enables operational flexibility. At June 30, 2012, we had approximately $785 million available for borrowings on our senior secured credit facility and total debt of approximately $1.05 billion. Our total debt, less available cash, was approximately $905 million, or approximately 2.0 times our annualized Adjusted EBITDA (a non-GAAP financial measure) for the first six months of 2012. 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. 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. As of September 30, 2012, we had $50 million outstanding on our senior secured credit facility.

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In December 2011, we completed a Corporate Reorganization and IPO. See " Corporate history and structure."

The following table summarizes our net acreage and producing wells as of June 30, 2012, total estimated net proved reserves as of December 31, 2011, and average daily production for the six months ended June 30, 2012 in our principal operating regions. Based on estimates in the report prepared by Ryder Scott, we operate wells that represent approximately 97% of the value of our proved developed oil and natural gas reserves as of December 31, 2011. In addition, the table shows our gross identified potential drilling locations and our proved undeveloped locations as of December 31, 2011.

	At December 31, 2011					Six months ended June 30, 2012	At June 30, 2012		
	Estimated net proved reserves(1)(2)			Identified potential drilling locations(4)					
								Producing wells	
	MBOE(3)	% of total reserves	% Oil	Total	PUD locations(5)	average daily production(6) (BOE/D)	Net acreage	Gross	Net
Permian Basin									
Permian Garden City	101,441	65%	52%	5,669	872	19,316	142,274	759	713
Permian Other							45,740		
Anadarko Granite Wash	45,101	29%	8%	335	207	7,931	37,924	184	138
Other Areas(7)	9,911	6%	3%			2,443	71,550	347	174
New Ventures(8)							106,788	1	1
Total	156,453	100%	36%	6,004	1,079	29,690	404,276	1,291	1,026

(1) Our estimated net proved reserves were prepared by Ryder Scott as of December 31, 2011 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 twelve-month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable twelve-month period), held constant throughout the life of the properties. The reference prices were $92.71/Bbl for oil and $3.99/MMBtu for natural gas for the twelve months ended December 31, 2011.

(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, 2011 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 $7.48/Mcf in the Permian area and $4.88/Mcf in the Anadarko Granite Wash area.

(3) MBbl equivalents ("MBOE") are calculated using a conversion rate of six MMcf per one MBbl.

(4) See the Glossary of Oil and Natural Gas Terms for the definition of "identified potential drilling locations" and below for more information regarding the processes and criteria through which these potential drilling locations were identified.

(5) Represents the number of identified potential drilling locations to which proved undeveloped reserves are

attributable.

(6) 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.

(7) Includes our acreage in the gas prone Eastern Anadarko (26,929 net acres) and Central Texas Panhandle (44,621 net acres).

(8) Includes 99,144 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 7,643 net acres in other New Ventures. See "   New ventures."

At September 17, 2012, we had a total of 14 operated drilling rigs working. Ten of these rigs were working on our properties in the Permian Basin, six drilling vertical wells and four drilling horizontal wells. Three rigs were working on our properties in the Anadarko Granite Wash, all drilling horizontal wells. One rig was drilling an exploratory well in our New Ventures.

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

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focused primarily on horizontal drilling in the Permian Basin and, to a lesser extent, the Anadarko Granite Wash.

In the drilling and development of hydrocarbon reserves, there are three key factors that can have an effect on our objective of establishing commercial production. In addition to the data collected and the wells we have drilled, each of these factors must be addressed in order to reduce the risk and uncertainty associated with (or "de-risk") our exploration and development program:

- Does the prospective reservoir underlie our acreage position?
- Are the petrophysics of the reservoir rock such that it contains hydrocarbons that can be recovered?
- Can the hydrocarbons be produced on a commercial basis?

We carefully assess and monitor all three 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 Anadarko Basin may extend back approximately 50 years and in the Permian Basin more than 80 years). We also utilize our laboratory and field derived data from whole cores, sidewall cores, well cuttings, mudlogs and open-hole well logs to understand the petrophysics of the rock characteristics prior to the commencement of any completion operations. Finally, after defining the reservoir, our engineers utilize their technical expertise to develop completion programs that we believe will maximize the amount of hydrocarbons that can be recovered. As more wells are completed in the targeted reservoir and additional data becomes available, the process is further refined (and further de-risked) at which time we can begin to implement a development plan for the area in order to minimize costs and maximize recoveries (as we are doing for our Permian-Garden City acreage).

In the Permian Basin, 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 will now be centered in bringing forward the upside potential in the Wolfcamp and Cline shales in the remainder of our Permian 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 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 has allowed us to define the 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.

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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 both 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 identified potential drilling locations will be influenced by several factors, including commodity prices, capital requirements, RRC well-spacing requirements and the continuation of the positive results from our ongoing development drilling program.

Utilizing the factors noted above, as of December 31, 2011, we had identified approximately 6,000 gross potential drilling locations on our acreage, with more than 5,600 in the Permian-Garden City area. As we have continued to de-risk our acreage in 2012, we have begun implementing a drilling plan that focuses our drilling program on horizontal wells and is also concentrated on optimizing resource recoveries and production through the drilling of longer laterals where possible. As we continue to de-risk our acreage and implement this plan, the number of potential locations will change based on the economics of each horizontal play. This will be the case for both our development program in the Permian-Garden City area (considered a resource play) and in the Anadarko Basin for Granite Wash (a conventional play). We expect that the focus of the drilling programs in both the Permian-Garden City area and Anadarko Granite Wash will be on horizontal exploration and development.

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. We have an inventory of approximately 6,000 identified potential drilling locations as of December 31, 2011. As of June 30, 2012, such locations are on 142,274 net acres in the Permian-Garden City area and 37,924 net acres in the Anadarko Granite Wash. We believe this inventory 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 33 horizontal Cline wells and 14 horizontal Upper Wolfcamp wells, we believe we have confirmed the horizontal development potential of the Cline and Upper Wolfcamp shales on approximately 50% and 45%, respectively, of our Permian-Garden City acreage. 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. This enables us to create a plan to systematically and efficiently develop this acreage position as a resource play. Our future implementation plan will provide flexibility to include potential 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

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collecting technical data across our Permian-Garden City acreage position, as reflected in our 2012 capital budget allocation.

Capitalize on technical expertise. We intend to leverage 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, and a number of horizontal tests to date, primarily in the Upper Wolfcamp and Cline shales in the Permian-Garden City area, we believe we have de-risked a significant portion of such acreage.

We intend to continue to make substantial 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 emphasizing our horizontal program, we can increase the efficiency of our resource recovery in the multiple vertically stacked producing horizons on our acreage in both our Permian and Anadarko Granite Wash plays. We are drilling 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. 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. Laredo is the operator of our joint ventures, having drilled 24 wells under the ExxonMobil joint venture and 130 wells under the Linn Energy joint venture as of September 17, 2012.

Evaluate and pursue value-enhancing acquisitions, mergers and joint ventures. While we believe our multi-year inventory of identified potential drilling locations provides us with significant growth opportunities, we will continue to evaluate strategically compelling asset acquisitions, mergers and joint ventures. Any transaction we pursue will either generally complement our asset base or provide an anticipated competitive economic proposition relative to our existing opportunities or market conditions. Our Laredo-operated joint ventures with ExxonMobil and Linn Energy, our 2008 acquisition of properties from Linn Energy and our 2011 acquisition of Broad Oak are examples of this strategy.

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, maki