Laredo Petroleum Texas, LLC
Form 424B3
July 02, 2012

Use these links to rapidly review the document
TABLE OF CONTENTS
INDEX TO FINANCIAL STATEMENTS

Table of Contents

**Filed Pursuant to Rule 424(b)(3)**
**Registration No. 333-182172**

**PROSPECTUS**

# *Offer To Exchange Up To $500,000,000 of 7 3/8% Senior Notes Due 2022, That Have Not Been Registered Under The Securities Act of 1933 For Up To $500,000,000 of 7 3/8% Senior Notes Due 2022, That Have Been Registered Under The Securities Act of 1933*

**Terms of the New 7 3/8% Senior Notes due 2022 Offered in the Exchange Offer:**

The terms of the new notes are identical to the terms of the old notes that were issued on April 27, 2012, except that the new notes will be registered under the Securities Act of 1933 and will not contain restrictions on transfer, registration rights or provisions for additional interest.

**Terms of the Exchange Offer:**

We are offering to exchange up to $500,000,000 of old notes for new notes with materially identical terms that have been registered under the Securities Act of 1933 and are freely tradable.

We will exchange all old notes that you validly tender and do not validly withdraw before the exchange offer expires for an equal principal amount of new notes.

The exchange offer expires at 5:00 p.m., New York City time, on July 31, 2012, unless extended.

Tenders of old notes may be withdrawn at any time prior to the expiration of the exchange offer.

The exchange of new notes for old notes will not be a taxable event for U.S. federal income tax purposes.

Broker-dealers who receive new notes pursuant to the exchange offer acknowledge that they will deliver a prospectus in connection with any resale of such new notes.

Broker-dealers who acquired the old notes as a result of market-making or other trading activities may use the prospectus for the exchange offer, as supplemented or amended, in connection with resales of the new notes.

**You should carefully consider the risk factors beginning on page 15 of this prospectus and the other risk factors discussed in Laredo Petroleum Holdings, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, which are incorporated herein by reference, before participating in the exchange offer.**

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

The date of this prospectus is June 29, 2012.

**This prospectus is part of a registration statement we filed with the Securities and Exchange Commission ("SEC"). In making your investment decision, you should rely only on the information contained in, or incorporated by reference into, this prospectus and in the accompanying letter of transmittal. We have not authorized anyone to provide you with any other information. We are not making an offer to sell these securities or soliciting an offer to buy these securities in any jurisdiction where an offer or solicitation is not authorized or in which the person making that offer or solicitation is not qualified to do so or to anyone whom it is unlawful to make an offer or solicitation. You should not assume that the information contained in, or incorporated by reference into, this prospectus is accurate as of any date other than the date on the front cover of this prospectus or the date of such incorporated documents, as the case may be.**

**TABLE OF CONTENTS**

Table of Contents

In this prospectus, we refer to the notes to be issued in the exchange offer as the "new notes," and we refer to the $500 million principal amount of our 7$^3/_8$% senior notes due 2022 issued on April 27, 2012 as the "old notes." We refer to the new notes and the old notes collectively as the "notes." References to the "issuer" refer to Laredo Petroleum, Inc., a Delaware corporation and a wholly-owned subsidiary of the Parent Guarantor. References to the "Parent Guarantor" refer to Laredo Petroleum Holdings, Inc., a Delaware corporation. References to "subsidiaries" refer to the Parent Guarantor's subsidiaries: Laredo Petroleum, Inc., Laredo Petroleum Dallas, Inc., a Delaware corporation, Laredo Gas Services, LLC, a Delaware limited liability company, and Laredo Petroleum Texas, LLC, a Texas limited liability company. References to "Laredo," "we," "us" or "our" refer to Laredo Petroleum, LLC, a Delaware limited liability company, together with its subsidiaries, including the issuer, for periods prior to our corporate reorganization in December 2011, and to the Parent Guarantor together with its subsidiaries, including the issuer, for periods after our corporate reorganization, unless otherwise indicated or the context otherwise requires. References to "guarantors" refer to the Parent Guarantor and each of its subsidiaries that guarantee amounts outstanding on the notes on a joint and several basis.

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.

This prospectus incorporates important business and financial information about us that is not included or delivered with this prospectus. Such information is available without charge to holders of old notes upon written or oral request made to Laredo Petroleum, Inc., 15 W. Sixth Street, Suite 1800, Tulsa, Oklahoma 74119, Attention: Investor Relations (Telephone (918) 513-4570). To obtain timely delivery of any requested information, holders of old notes must make any request no later than five business days prior to the expiration of the exchange offer.

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this prospectus includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this prospectus, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project," "may," "will," "should," "plan," "predict," "potential," "foresee," "goal," "pursue," "target," "continue," "suggest" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. 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;

Table of Contents

- 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;
- 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 indenture governing the 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, as well as the risk factors set forth in Laredo Petroleum Holdings, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011 (the "2011 Annual Report"), Laredo Petroleum Holdings, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 (the "Quarterly Report") and those set forth from time to time in our filings with the SEC. In light of such risks and uncertainties, we caution you not to rely on these forward-looking statements in deciding whether to invest in the notes.

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 oil and 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.

Table of Contents

## PROSPECTUS SUMMARY

*This summary highlights some of the information contained in this prospectus and does not contain all of the information that may be important to you. You should read this entire prospectus, the documents incorporated by reference and the documents to which we refer you before making an investment decision. You should carefully consider the information set forth under "Risk Factors" beginning on page 15 of this prospectus and discussed in the 2011 Annual Report and Quarterly Report, and the other cautionary statements described in this prospectus. In addition, certain statements include forward looking information that involves risks and uncertainties. See "Cautionary Statement Regarding Forward-Looking Statements."*

### Company Overview

We are an independent energy company focused on the exploration, development and acquisition of oil and natural gas in the Permian and Mid-Continent regions of the United States. Our activities are primarily focused in the Wolfberry and deeper horizons of the Permian Basin in West Texas and the Anadarko Granite Wash in the Texas Panhandle and Western Oklahoma, where we have assembled 174,608 net acres and 37,320 net acres, respectively, as of March 31, 2012. The oil and liquids-rich Permian Basin and the liquids-rich Anadarko Granite Wash are characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and significant initial production rates.

Since our inception, we have rapidly grown our cash flow, production and reserves through our drilling program. We also seek acquisition opportunities that are complementary to our assets and provide upside potential that is competitive with our existing property portfolio. On July 1, 2011, we completed the acquisition of Broad Oak for a combination of equity and cash. This acquisition provided us incremental scale and significant additional exposure to attractive vertical and horizontal oil and liquids-rich natural gas opportunities. The acquired properties are concentrated on a contiguous land position located in the Permian Basin, primarily in Reagan County, and are being drilled targeting Wolfberry production. This acreage, totaling approximately 64,000 net acres, approximately doubled our Permian Basin position and is immediately south of and on trend with our legacy Permian Basin properties in Glasscock and Howard Counties. We believe the success Laredo has achieved to date in drilling our vertical and horizontal wells may add significant value to this acquired acreage. In December 2011, we completed a corporate reorganization and initial public offering of Laredo Petroleum Holdings, Inc.'s common stock (the "IPO"). See "  Corporate History and Structure."

Our net average daily production for the three months ended March 31, 2012 was approximately 27,995 BOE/D, and our net proved reserves were an estimated 156,453 MBOE as of December 31, 2011. From our formation in 2006 through May 31, 2012, we have drilled over 900 gross vertical and horizontal wells with a success rate of approximately 99%. Our drilling activity has been and will continue to be focused on liquids-rich opportunities in the Permian Basin and Anadarko Granite Wash, where we see liquids-rich natural gas that ranges from 1,225 to 1,460 Btu per cubic foot and 1,115 to 1,230 Btu per cubic foot, respectively. Pursuant to our existing percentage of proceeds contracts during March 31, 2012, our natural gas liquids yield was 130 Bbls/MMcf in the Permian Basin and 69 Bbls/MMcf in the Anadarko Granite Wash.

We maintain a conservative financial profile in order to preserve operational flexibility and financial stability. At March 31, 2012, on a pro forma basis, after giving effect to the offering of $500 million of old notes on April 27, 2012 and the application of the proceeds therefrom, we would have had approximately $785 million available for borrowings under the issuer's senior secured credit facility (giving effect to the increase in the borrowing base) and total debt of approximately $1.05 billion, which is 2.3 times our annualized Adjusted EBITDA, a non-GAAP financial measure, for the first three months of 2012. We believe that our operating cash flow and the aforementioned liquidity sources provide us with the ability to implement our planned exploration and development activities.

Table of Contents

**Recent Developments**

*Credit Agreement Amendment.* On April 24, 2012, we amended the issuer's $1.0 billion senior secured credit facility to increase our ability to issue senior notes from up to $550 million to up to $1.05 billion. On April 27, 2012, we further amended the senior secured credit facility to increase the facility capacity to $2.0 billion and the borrowing base under the facility to $785 million.

**Corporate History and Structure**

Laredo Petroleum, Inc. was founded in October 2006 by Randy A. Foutch, our Chairman and Chief Executive Officer, and other members of our management team to acquire, develop and operate oil and gas properties in the Permian and Mid-Continent regions of the United States. In 2007, affiliates of Warburg Pincus LLC (``Warburg Pincus"), our institutional investor, and Laredo Petroleum, Inc.'s management formed Laredo Petroleum, LLC as a holding company and entered into a limited liability company agreement, which provided for Laredo Petroleum, LLC's initial funding with an equity commitment of $300 million from Warburg Pincus, certain members of our management team and our independent directors. The stockholders of Laredo Petroleum, Inc. contributed their common stock in Laredo Petroleum, Inc. to Laredo Petroleum, LLC in return for equity units in Laredo Petroleum, LLC, and Laredo Petroleum, Inc. became a wholly-owned subsidiary of Laredo Petroleum, LLC. In October 2008, Laredo Petroleum, LLC's limited liability company agreement was amended and a new series of equity units was created to provide for an additional $300 million equity program.

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.

Laredo Petroleum Holdings, Inc. was incorporated on August 12, 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"). In the Corporate Reorganization, all of the outstanding preferred and certain series 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 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.

Laredo Petroleum, Inc. has three wholly-owned subsidiaries: Laredo Petroleum Texas, LLC, a Texas limited liability company formed in March 2007; Laredo Gas Services, LLC, a Delaware limited liability company formed in November 2007; and Laredo Petroleum Dallas, Inc., a Delaware corporation formed in May 2006, formerly known as Broad Oak Energy, Inc.

Laredo Petroleum, Inc. is the borrower under its senior secured credit facility as well as the issuer of the notes and the $9^1/_2$% senior notes due 2019, which we refer to as the 2019 senior notes. Laredo Petroleum Holdings, Inc. and all of its subsidiaries (other than Laredo Petroleum, Inc.) are guarantors of the obligations under the senior secured credit facility, the notes and the 2019 senior notes.

Table of Contents

The following diagram indicates our current ownership structure.

**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. For additional information regarding our business properties and financial condition, please refer to the documents referenced in the section entitled "Where You Can Find More Information."

Table of Contents

**The Exchange Offer**

On April 27, 2012, we completed a private offering of $500 million aggregate principal amount of the old notes. We entered into a registration rights agreement with the initial purchasers in connection with this offering in which we agreed to deliver to you this prospectus and to use commercially reasonable efforts to complete the exchange offer within 365 days after the date of the initial issuance of the old notes issued on April 27, 2012.

| | |
|---|---|
| Old Notes | On April 27, 2012, we issued $500 million aggregate principal amount of 7 3/8% senior notes due 2022. |
| Exchange Offer | We are offering to exchange up to $500 million aggregate principal amount of the new notes for an equal amount of the old notes. |
| Expiration Date | The exchange offer will expire at 5:00 p.m., New York City time, on July 31, 2012, unless we decide to extend it. |
| Conditions to the Exchange Offer | The registration rights agreement does not require us to accept old notes for exchange if the exchange offer, or the making of any exchange by a holder of the old notes, would violate any applicable law or interpretation of the staff of the SEC. The exchange offer is not conditioned on a minimum aggregate principal amount of old notes being tendered. |
| Procedures for Tendering Old Notes | To participate in the exchange offer, you must follow the procedures established by The Depository Trust Company, which we call "DTC," for tendering notes held in book-entry form. These procedures, which we call "ATOP," require that (i) the exchange agent receive, prior to the expiration date of the exchange offer, a computer generated message known as an "agent's message" that is transmitted through DTC's automated tender offer program, and (ii) DTC confirms that:<br><br>DTC has received your instructions to exchange your notes, and<br><br>You agree to be bound by the terms of the letter of transmittal.<br>For more information on tendering your old notes, please refer to the sections in this prospectus entitled "Exchange Offer Terms of the Exchange Offer," "Exchange Offer Procedures for Tendering" and "Description of the Notes Book-Entry, Delivery and Form." |
| Guaranteed Delivery Procedures | None. |
| Withdrawal of Tenders | You may withdraw your tender of old notes at any time prior to the expiration date. To withdraw, you must submit a notice of withdrawal to the exchange agent using ATOP procedures before 5:00 p.m., New York City time, on the expiration date of the exchange offer. Please refer to the section in this prospectus entitled "Exchange Offer Withdrawal of Tenders." |

Table of Contents

| | |
|---|---|
| Acceptance of Old Notes and Delivery of New Notes | If you fulfill all conditions required for proper acceptance of old notes, we will accept any and all old notes that you properly tender in the exchange offer before 5:00 p.m., New York City time, on the expiration date. We will return any old notes that we do not accept for exchange to you without expense promptly after the expiration date and acceptance of the old notes for exchange. Please refer to the section in this prospectus entitled "Exchange Offer Terms of the Exchange Offer." |
| Fees and Expenses | We will bear expenses related to the exchange offer. Please refer to the section in this prospectus entitled "Exchange Offer Fees and Expenses." |
| Use of Proceeds | The issuance of the new notes will not provide us with any new proceeds. We are making this exchange offer solely to satisfy our obligations under our registration rights agreement. |
| Consequences of Failure to Exchange Old Notes | If you do not exchange your old notes in this exchange offer, you will no longer be able to require us to register the old notes under the Securities Act except in limited circumstances provided under the registration rights agreement. In addition, you will not be able to resell, offer to resell or otherwise transfer the old notes unless we have registered the old notes under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act. |
| U.S. Federal Income Tax Consequences | The exchange of new notes for old notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes. Please read "Material United States Federal Income Tax Consequences." |

Table of Contents

| | |
|---|---|
| Exchange Agent | We have appointed Wells Fargo Bank, N.A. as exchange agent for the exchange offer. You should direct questions and requests for assistance, requests for additional copies of this prospectus or the letter of transmittal to the exchange agent as follows:<br>*By registered & certified mail:*<br>WELLS FARGO BANK, N.A.<br>Corporate Trust Operations<br>MAC : N9303-121<br>P.O. Box 1517<br>Minneapolis, MN 55480<br>*By regular mail or overnight courier:*<br>WELLS FARGO BANK, N.A.<br>Corporate Trust Operations<br>MAC : N9303-121<br>6th St & Marquette Avenue<br>Minneapolis, MN 55479<br>*In person by hand only:*<br>WELLS FARGO BANK, N.A.<br>Corporate Trust Services<br>Northstar East Building 12th Floor<br>608 Second Avenue South<br>Minneapolis, MN 55402<br>Eligible institutions may make requests by facsimile at<br>(612) 667-6282 and may confirm facsimile delivery by calling (800) 344-5128. |

Table of Contents

**Terms of the New Notes**

The new notes will be identical to the old notes except that the new notes are registered under the Securities Act and will not have restrictions on transfer, registration rights or provisions for additional interest. The new notes will evidence the same debt as the old notes, and the same indenture will govern the new notes and the old notes.

The following summary contains basic information about the new notes and is not intended to be complete. It does not contain all information that may be important to you. For a more complete understanding of the new notes, please refer to the section entitled "Description of the Notes" in this prospectus.

| | |
|---|---|
| Issuer | Laredo Petroleum, Inc., a direct wholly-owned subsidiary of Laredo Petroleum Holdings, Inc. |
| New Notes Offered | \$500 million aggregate principal amount of $7^3/_8$% senior notes due 2022, registered under the Securities Act. The old notes and the new notes will be treated as a single class of securities under the indenture, including, without limitation, for purposes of waivers, amendments, redemptions and offers to purchase. |
| Maturity Date | May 1, 2022. |
| Interest | The new notes will bear interest at a rate of $7^3/_8$% per annum, payable semi-annually, in cash in arrears, on May 1 and November 1 of each year, commencing on the first such date next following the date on which the exchange offer is consummated. |
| Guarantees | Each of Laredo Petroleum Holdings, Inc. and its existing subsidiaries (other than the issuer) will fully and unconditionally guarantee, jointly and severally, the new notes initially and (except for Laredo Petroleum Holdings, Inc.) so long as such entity guarantees the issuer's senior secured credit facility or other debt in excess of \$5 million. Not all of Laredo Petroleum Holdings, Inc.'s future subsidiaries will be required to become guarantors. If the issuer cannot make payments on the new notes when they are due, the guarantors must make them instead. Please read "Description of the Notes Guarantees."<br>Each guarantee will rank:<br>senior in right of payment to any future subordinated indebtedness of the guarantor;<br>equally in right of payment to all existing and future senior unsecured indebtedness of the guarantor, including the guarantee of the 2019 senior notes; and<br>effectively subordinate in right of payment to all existing and future secured indebtedness of the guarantor, including its guarantee of indebtedness under our senior secured credit facility, to the extent of the value of the assets securing such indebtedness. |

Table of Contents

As of March 31, 2012, on a pro forma basis after giving effect to the offering of $500 million of old notes on April 27, 2012 and the application of the net proceeds therefrom, the guarantees of the notes would have been effectively subordinated to $0 of secured indebtedness, with the issuer having approximately $785 million of borrowing capacity available under our senior secured credit facility (giving effect to the increase in the borrowing base), subject to compliance with financial covenants, the guarantees of which would be effectively senior to the guarantees of the notes (to the extent of the value of the assets securing such indebtedness).

Ranking

The new notes will be the issuer's unsecured senior obligations. Accordingly, they will rank:

- senior in right of payment to all the issuer's existing and future subordinated indebtedness;
- equally in right of payment to all of the issuer's existing and future senior indebtedness, including the 2019 senior notes;
- effectively subordinate in right of payment to all of the issuer's existing and future secured indebtedness, including indebtedness under the issuer's senior secured credit facility, to the extent of the value of the assets securing such indebtedness; and
- effectively subordinate to all indebtedness and other liabilities of any future non-guarantor subsidiaries.

As of March 31, 2012, on a pro forma basis after giving effect to the offering of $500 million of old notes on April 27, 2012 and the application of the net proceeds therefrom, the notes would have been effectively subordinated to $0 of secured indebtedness, with the issuer having approximately $785 million of borrowing capacity available under our senior secured credit facility (giving effect to the increase in the borrowing base), subject to compliance with financial covenants, all of which would be effectively senior to the notes (to the extent of the value of the assets securing such indebtedness).

Table of Contents

| | |
|---|---|
| Optional Redemption | The issuer will have the option to redeem the new notes, in whole or in part, at any time on or after May 1, 2017, at the redemption prices described in this prospectus under the heading "Description of the Notes Optional Redemption," together with any accrued and unpaid interest to, but not including, the date of redemption. In addition, before May 1, 2017, the issuer may redeem all or any part of the notes at the make-whole price set forth under "Description of the Notes Optional Redemption." In addition, before May 1, 2015, the issuer may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the notes with the net proceeds of a public or private equity offering at a redemption price of 107.375% of the principal amount of the notes, plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the notes issued under the indenture governing the notes remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. If a change of control occurs prior to May 1, 2013, the issuer may redeem all, but not less than all, of the notes at a redemption price equal to 110% of the principal amount of the notes plus any accrued and unpaid interest to, but not including, the date of redemption. |
| Change of Control | If a change of control event occurs, each holder of new notes may require the issuer to repurchase all or a portion of its new notes for cash at a price equal to 101% of the aggregate principal amount of such new notes, plus any accrued and unpaid interest to, but not including, the date of repurchase. |
| Certain Other Covenants | The indenture contains covenants that limit, among other things, the ability of Laredo Petroleum Holdings, Inc. and some of its subsidiaries (including the issuer) to:<br><br>pay distributions or dividends on, or purchase, redeem or otherwise acquire, equity interests;<br><br>make certain investments;<br><br>incur additional indebtedness or liens;<br><br>sell certain assets or merge with or into other companies;<br><br>engage in transactions with affiliates; and<br><br>enter into sale and leaseback transactions.<br>These covenants are subject to a number of important qualifications and limitations. In addition, substantially all of the covenants will be suspended before the new notes mature if both of two specified ratings agencies assign the new notes an investment grade rating in the future and no event of default exists under the indenture governing the new notes. See "Description of the Notes Certain Covenants." |

| | |
|---|---|
| Transfer Restrictions, Absence of a Public Market for the New Notes | The new notes generally will be freely transferable, but will also be new securities for which there will not initially be a market. There can be no assurance as to the development of liquidity of any market for the new notes. We do not intend to apply for a listing of the new notes on any securities exchange or any automated dealer quotation system. |
| Risk Factors | Investing in the new notes involves risks. See "Risk Factors" beginning on page 15 of this prospectus and in the 2011 Annual Report and the Quarterly Report for a discussion of certain factors you should consider in evaluating whether or not to tender your old notes. |
| Form of Exchange Notes | The new notes will be represented initially by one or more global notes. The global new notes will be deposited with the trustee, as custodian for DTC. |
| Trustee, Registrar and Exchange Agent | Wells Fargo Bank, National Association. |
| Governing Law | The new notes and the indenture governing the new notes will be governed by and construed in accordance with the laws of the State of New York. |
| Same-Day Settlement | The global new notes will be shown on, and transfers of the global new notes will be effected only through, records maintained in book entry form by DTC and its direct and indirect participants. The new notes are expected to trade in DTC's Same Day Funds Settlement System until maturity or redemption. Therefore, secondary market trading activity in the new notes will be settled in immediately available funds. |

Table of Contents

**Ratio of Earnings to Fixed Charges**

The following table sets forth our ratio of earnings to fixed charges for the periods presented:

| | For the three months ended March 31, | | For the years ended December 31, | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Pro forma 2012 | 2012 | Pro forma 2011 | 2011 | 2010 | 2009 | 2008 | 2007 |
| Ratio of earnings to fixed charges (1) | 2.3x(2) | 3.6x | 2.4x(3) | 4.2x | 4.2x | (4) | (4) | (4) |

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of pretax income (loss) plus fixed charges less interest capitalized. "Fixed charges" represents interest incurred, amortization of deferred debt offering costs and that portion of rental expense on operating leases deemed to be the equivalent of interest.

(2) Because the net proceeds of the old notes were used to repay indebtedness, the pro forma impact on the amount of fixed charges causes our earnings to cover fixed charges to change by greater than 10% for the three months ended March 31, 2012. At March 31, 2012, we had approximately $230.0 million of borrowings outstanding under our senior secured credit facility and $550.0 million in 2019 senior notes. The weighted average interest rate paid on amounts outstanding under our senior secured credit facility for the three months ended March 31, 2012 was 0.55% and under the 2019 senior notes was 2.37% (excluding the impact of our interest rate swaps).

(3) Because the net proceeds of the offering of the old notes were used to repay indebtedness, the pro forma impact on the amount of fixed charges causes our earnings to cover fixed charges to change by greater than 10% for the year ended December 31, 2011. At December 31, 2011, we had approximately $85.0 million of borrowings outstanding under our senior secured credit facility and $550.0 million in 2019 senior notes. For the year ended December 31, 2011, the weighted average interest rates paid on amounts outstanding under our senior secured credit facility, the term loan, the Broad Oak credit facility and the 2019 senior notes was 2.07%, 0.51%, 3.07% and 8.98% (excluding the impact of our interest rate swaps).

(4) Due to our net operating losses for each of the years ended December 31, 2009, 2008 and 2007, the respective ratios of coverage were less than 1:1. To achieve the ratio coverage of 1:1, we would have needed additional earnings of approximately $258.5 million, $245.8 million, and $7.5 million, respectively.

Table of Contents

**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," "Selected Historical Consolidated Financial Data" 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 three months ended March 31, 2012 and 2011 and the consolidated balance sheet as of March 31, 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 three months ended March 31, 2012 | 2011 | For the years ended December 31, 2011 | 2010 | 2009 | 2008(1) | 2007(2) |
|---|---|---|---|---|---|---|---|
| | (unaudited) | | | | | | (unaudited) |
| Statement of operations data: | | | | | | | |
| Total revenues | $ 150,348 | $ 107,111 | $ 510,270 | $ 242,000 | $ 96,574 | $ 74,187 | $ 9,628 |
| Total costs and expenses | 94,959 | 57,949 | 308,371 | 169,018 | 350,103 | 350,653 | 17,251 |
| Operating income (loss) | 55,389 | 49,162 | 201,899 | 72,982 | (253,529) | (276,466) | (7,623) |
| Non-operating income (expense), net | (14,397) | (41,895) | (36,971) | (12,546) | (4,972) | 30,702 | 167 |
| Income (loss) before income taxes | 40,992 | 7,267 | 164,928 | 60,436 | (258,501) | (245,764) | (7,456) |
| Net income (loss) | 26,235 | 4,670 | 105,554 | 86,248 | (184,495) | (192,047) | (6,051) |
| Net income per common share: | | | | | | | |
| Basic | $ 0.21 | | $ 0.98 | | | | |
| Diluted | $ 0.20 | | $ 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.

| (in thousands) | As of March 31, 2012 | As of December 31, 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|---|
| | (unaudited) | | | | | (unaudited) |
| Balance sheet data: | | | | | | |
| Cash and cash equivalents | $ 12,212 | $ 28,002 | $ 31,235 | $ 14,987 | $ 13,512 | $ 6,937 |
| Net property and equipment | 1,556,449 | 1,378,509 | 809,893 | 396,100 | 350,702 | 137,852 |
| Total assets | 1,798,482 | 1,627,652 | 1,068,160 | 625,344 | 578,387 | 171,799 |
| Current liabilities | 205,948 | 214,361 | 150,243 | 79,265 | 101,864 | 16,809 |
| Long-term debt | 781,913 | 636,961 | 491,600 | 247,100 | 148,600 | 44,500 |
| Stockholders'/unit holders' equity | 788,495 | 760,013 | 411,099 | 289,107 | 318,364 | 109,707 |

Table of Contents

| (in thousands) | For the three months ended March 31, 2012 | 2011 | For the years ended December 31, 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|---|---|
| | (unaudited) | | | | | | (unaudited) |
| Other financial data: | | | | | | | |
| Net cash provided by operating activities | $ 91,402 | $ 75,988 | $ 344,076 | $ 157,043 | $ 112,669 | $ 25,332 | $ 5,019 |
| Net cash used in investing activities | (252,192) | (192,360) | (706,787) | (460,547) | (361,333) | (490,897) | (131,153) |
| Net cash provided by financing activities | 145,000 | 100,890 | 359,478 | 319,752 | 250,139 | 472,140 | 126,726 |

| (in thousands, unaudited) | For the three months ended March 31, 2012 | 2011 | For the years ended December 31, 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|---|---|
| Adjusted EBITDA(1) | $ 113,883 | $ 82,854 | $ 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."

Table of Contents

## 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 Company, L.P. ("Ryder Scott"), our independent reserve engineers. 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.

## RISK FACTORS

*Investing in the notes involves risks. You should carefully consider the information in this prospectus, including the matters addressed under "Cautionary Statement Regarding Forward-Looking Statements" and the risks below, as well as those discussed in the 2011 Annual Report and the Quarterly Report, together with all of the other information included in, or incorporated by reference into, this prospectus, before participating in the exchange offer.*

### Risks Related to the Notes

***We may not be able to generate sufficient cash to service all of our indebtedness, including the notes, and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.***

Our ability to make scheduled payments on or to refinance our debt obligations, including the notes, depends on our financial condition and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the notes. As a result of concern about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased for certain companies as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide funding to borrowers.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance our indebtedness, including the notes. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and the bank markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of our existing or future debt instruments and the indenture governing the notes may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our senior secured credit facility, the indenture governing the 2019 senior notes and the indenture governing the notes currently restrict our ability to dispose of assets and use the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

Our borrowing base is scheduled for semi-annual redetermination on May 1 and November 1 of each year and currently is $785 million. As of June 28, 2012, we had no outstanding debt under the senior secured credit facility. In the future, we may not be able to access adequate funding under our senior secured credit facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a subsequent semi-annual borrowing base redetermination or an unwillingness or inability on the part of our lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service the notes.

Table of Contents

***Despite our indebtedness level, we still may be able to incur significant additional amounts of debt.***

As of March 31, 2012, on a pro forma basis after giving effect to the offering of old notes and the application of the net proceeds therefrom, we would have had approximately $1.05 billion of indebtedness outstanding, represented by $500 million aggregate principal amount of the old notes, $550 million aggregate principal amount of 2019 senior notes and $0 in loans outstanding under our senior secured credit facility, as well as approximately $785 million of additional borrowing capacity available under our senior secured credit facility (giving effect to the increase in the borrowing base), subject to compliance with financial covenants. 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 indenture governing the notes, the indenture governing the 2019 senior notes and our senior secured credit facility are subject to a number of significant qualifications and exceptions, and under certain circumstances, the amount of indebtedness, including secured 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, including those relating to the notes. In addition, the indenture governing the notes will not prevent us from incurring obligations that do not constitute indebtedness under the indenture. See "Description of Other Indebtedness Senior Secured Credit Facility" and "Description of the Notes."

If we incur any additional indebtedness or other obligations, including trade payables, that rank equally with the notes, the holders of those obligations will be entitled to share ratably with you in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding up of our company. This may have the effect of reducing the amount of proceeds paid to you.

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

The indenture governing the notes, the indenture governing the 2019 senior notes and our senior secured credit facility 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

Table of Contents

all commitments to extend further credit. Such actions by those lenders could cause cross defaults under our other indebtedness, including the 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 of 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, including the notes.

***If we are unable to comply with the restrictions and covenants in the agreements governing the notes and other indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed and could impair our ability to make principal and interest payments on the notes.***

If we are unable to comply with the restrictions and covenants in the indenture governing the notes, in the indenture governing the 2019 senior notes, in our senior secured credit facility, or in any future debt financing agreements, there could be a default under the terms of these agreements. Our ability to comply with these restrictions and covenants, including meeting financial ratios and tests, may be affected by events beyond our control. As a result, we cannot assure you that we will be able to comply with these restrictions and covenants or meet these financial ratios or tests. Any default under the agreements governing our indebtedness, including a default under our senior secured credit facility, the indenture governing the 2019 senior notes or the indenture governing the notes, that is not waived by the requisite number of lenders, and the remedies sought by the holders of such indebtedness, could prevent us from paying principal, premium, if any, and interest on the notes and substantially decrease the market value of the notes. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants in the instruments governing our indebtedness (including covenants in our senior secured credit facility), we could be in default under the terms of these agreements. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders under our senior secured credit facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers from the required lenders under our senior secured credit facility or any other indebtedness to avoid being in default. If we breach our covenants under our senior secured credit facility or any other indebtedness and seek a waiver, we may not be able to obtain a waiver from the required lenders on terms that are acceptable to us, if at all. If this occurs, we would be in default under our senior secured credit facility or any other indebtedness, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

***The notes and the guarantees are unsecured and effectively subordinated to our secured indebtedness and to the debt of any non-guarantor subsidiaries.***

The notes and the guarantees will be general unsecured senior obligations of Laredo Petroleum, Inc. and each guarantor and will rank effectively junior to all of Laredo Petroleum, Inc.'s and each guarantor's existing and future secured indebtedness, including indebtedness under our senior secured credit facility, to the extent of the value of the collateral securing such indebtedness. As of March 31, 2012, Laredo Petroleum, Inc. and the guarantors had approximately $230 million of secured indebtedness. As of March 31, 2012, on a pro forma basis after giving effect to the offering of old notes and the application of the net proceeds therefrom, Laredo Petroleum, Inc. and the guarantors would have had approximately $0 of secured indebtedness and approximately $785 million of additional undrawn availability under our senior secured credit facility (giving effect to the increase in the borrowing base). The notes and the guarantees will also be effectively subordinated to any indebtedness of any future non-guarantor subsidiaries to the extent of the assets of those subsidiaries.

If we were unable to repay indebtedness under our senior secured credit facility, the lenders under that facility could foreclose on the pledged assets to the exclusion of holders of the notes, even if an event of default exists under the indenture governing the notes at such time. Furthermore, if the lenders foreclose and sell the pledged equity interests in any subsidiary guarantor in a transaction permitted under the terms of the indenture governing the notes, then such subsidiary guarantor will be released from its guarantee of the notes automatically and immediately upon such sale. In any such event, because the notes are not secured by any of such assets or by the equity interests in any such subsidiary guarantor, it is possible that there would be no assets from which your claims could be satisfied or, if any assets existed, they might be insufficient to satisfy your claims in full.

If Laredo Petroleum, Inc. or any guarantor is declared bankrupt, becomes insolvent or is liquidated, dissolved or reorganized, any of its secured indebtedness will be entitled to be paid in full from its assets or the assets of any guarantor securing that indebtedness before any payment may be made with respect to the notes or the affected guarantees, and creditors of any non-guarantor subsidiaries would be paid before you receive any amounts due under the notes to the extent of the value of our equity interests in such subsidiaries. Holders of the notes will participate ratably in the remaining assets of Laredo Petroleum, Inc. and the guarantors with all holders of any unsecured indebtedness of Laredo Petroleum, Inc. and the guarantors that do not rank junior in right of payment to the notes, based upon the respective amounts owed to each holder or creditor. In any of the foregoing events, there may not be sufficient assets to pay amounts due on the notes or the guarantees. As a result, holders of the notes would likely receive less, ratably, than holders of secured indebtedness and holders of debt of any future non-guarantor subsidiaries.

***Repayment of our debt, including the notes, is partially dependent on cash flow generated by our subsidiaries.***

Repayment of our indebtedness, including the notes, is partially dependent on the generation of cash flow by our subsidiaries and their ability to make such cash available to us, by dividend, debt repayment or otherwise. Unless they are guarantors of the notes, our subsidiaries will not have any obligation to pay amounts due on the notes or to make funds available for that purpose. Future non-guarantor subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of our indebtedness, including the notes. Each subsidiary is a distinct legal entity and, under certain circumstances, legal and contractual restrictions may limit our ability to obtain cash from future non-guarantor subsidiaries. While the indenture governing the notes will limit the ability of our non-guarantor subsidiaries to incur consensual restrictions on their ability to pay dividends or make other intercompany payments to us, these limitations are subject to certain qualifications and exceptions. In the event that we do not receive distributions from any future non-guarantor subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the notes.

***A financial failure by Laredo Petroleum Holdings, Inc. or its subsidiaries (including the issuer) may result in the assets of any or all of those entities becoming subject to the claims of all creditors of those entities.***

A financial failure by Laredo Petroleum Holdings, Inc. or its subsidiaries (including the issuer) could affect payment of the notes if a bankruptcy court were to substantively consolidate Laredo

Table of Contents

Petroleum Holdings, Inc. and its subsidiaries (including the issuer). If a bankruptcy court substantively consolidated Laredo Petroleum Holdings, Inc. and its subsidiaries (including the issuer), the assets of each entity would become subject to the claims of creditors of all entities. This would expose holders of notes not only to the usual impairments arising from bankruptcy, but also to potential dilution of the amount ultimately recoverable because of the larger creditor base. Furthermore, forced restructuring of the notes could occur through the "cram-down" provisions of the U.S. bankruptcy code. Under these provisions, the notes could be restructured over your objections as to their general terms, primarily interest rate and maturity.

***We may not be able to repurchase the notes in certain circumstances.***

Under the terms of the indenture governing the 2019 senior notes and the indenture governing the notes, we may be required to repurchase all or a portion of the 2019 senior notes and your notes if we sell certain assets or in the event of a change of control of Laredo Petroleum Holdings, Inc. In such event, we may not have enough funds to pay the repurchase price on a purchase date. The senior secured credit facility provides, and any future credit facilities or other debt agreements to which we become a party may provide, that our obligation to repurchase the 2019 senior notes and the notes would be an event of default under such agreement. As a result, we may be restricted or prohibited from repurchasing such notes. If we are prohibited from repurchasing such notes, we could seek the consent of our then-existing lenders to repurchase such notes, or we could attempt to refinance the borrowings that contain such prohibition. If we are unable to obtain any such consent or refinance such borrowings, we would not be able to repurchase such notes. Our failure to repurchase tendered notes would constitute a default under the indenture governing the 2019 senior notes and the indenture governing the notes and would constitute a default under the terms of our existing, or might constitute a default under the terms of our future, indebtedness.

The definition of "change of control" includes a phrase relating to the sale, assignment, conveyance, transfer, lease or other disposition, in one or a series of related transactions, of "all or substantially all" of the assets of Laredo Petroleum, Inc., Laredo Petroleum Holdings, Inc. and their restricted subsidiaries, taken as a whole. Thus, only asset dispositions constituting a "series of related transactions" are aggregated in determining whether a "change of control" arising from the sale of "substantially all" of the assets has taken place. Moreover, although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, whether assets are disposed of in a single transaction or a series of related transactions, your ability to require us to repurchase your notes as a result of a sale, assignment, conveyance, transfer, lease or other disposition of less than all of the assets of Laredo Petroleum, Inc., Laredo Petroleum Holdings, Inc. and their restricted subsidiaries to another person or group may be uncertain. In addition, a recent Delaware Chancery Court decision raised questions about the enforceability of provisions, which are similar to those in the indenture governing the notes, related to the change of control as a result of a change in the composition of our board of directors. Accordingly, your ability to require us to repurchase your notes as a result of a change in the composition of the directors on our board of directors may be uncertain.

The term "change of control" is limited to certain specified transactions and may not include other events that might adversely affect our financial condition. Our obligation to repurchase the 2019 senior notes or the notes upon a change of control would not necessarily afford holders of such notes protection in the event of a highly leveraged transaction, reorganization, merger or similar transaction. In addition, holders of such notes may not be entitled to require us to purchase their notes in certain circumstances involving a significant change in the composition of Laredo Petroleum Holdings, Inc.'s board of directors, including in connection with a proxy contest in which Laredo Petroleum Holdings, Inc.'s board of directors does not endorse or recommend a dissident slate of directors but approves them as directors for purposes of the "change of control" definition in the indenture. See "Description of the Notes Change of Control."

***Federal and state fraudulent transfer laws may permit a court to void the notes and the guarantees, subordinate claims in respect of the notes and the guarantees and require noteholders to return payments received and, if that occurs, you may not receive any payments on the notes.***

Federal and state fraudulent transfer and conveyance statutes may apply to the issuance of the notes and the incurrence of any guarantees of the notes, including the guarantee by the guarantors entered into upon issuance of the notes and subsidiary guarantees (if any) that may be entered into thereafter under the terms of the indenture governing the notes. Under federal bankruptcy law and comparable provisions of state fraudulent transfer or conveyance laws, which may vary from state to state, the notes or guarantees could be voided as a fraudulent transfer or conveyance if the court found that (1) we or any of the guarantors, as applicable, issued the notes or incurred the guarantees with the intent of hindering, delaying or defrauding creditors or (2) we or any of the guarantors, as applicable, received less than the reasonably equivalent value or fair consideration in return for either issuing the notes or incurring the guarantees and, in the case of (2) only, one of the following is also true at the time thereof:

- we or any of the guarantors, as applicable, were insolvent or rendered insolvent by reason of the issuance of the notes or the incurrence of the guarantees;

- the issuance of the notes or the incurrence of the guarantees left us or any of the guarantors, as applicable, with an unreasonably small amount of capital to carry on the business;

- we or any of the guarantors intended to, or believed that we or such guarantor would, incur debts beyond our or such guarantor's ability to pay such debts as they mature; or

- we or any of the guarantors were a defendant in an action for money damages, or had a judgment for money damages docketed against us or such guarantor if, in either case, after final judgment, the judgment is unsatisfied.

A court would likely find that we or a guarantor did not receive reasonably equivalent value or fair consideration for the notes or such guarantee if we or such guarantor did not substantially benefit directly or indirectly from the issuance of the notes or the applicable guarantee. As a general matter, value is given for a transfer or an obligation if, in exchange for the transfer or obligation, property is transferred or an antecedent debt is secured or satisfied. A debtor will generally not be considered to have received value in connection with a debt offering if the debtor uses the proceeds of that offering to make a dividend payment or otherwise retire or redeem equity securities issued by the debtor.

We cannot be certain as to the standards a court would use to determine whether or not we or the guarantors were solvent at the relevant time or, regardless of the standard that a court uses, that the issuance of the guarantees would not be further subordinated to our or any of our guarantors' other debt. Generally, however, an entity would be considered insolvent at the time it incurred indebtedness if:

- the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all its assets;

- the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or

- it could not pay its debts as they become due.

If a court were to find that the issuance of the notes or the incurrence of the guarantee was a fraudulent transfer or conveyance, the court could void the payment obligations under the notes or such guarantee or further subordinate the notes or such guarantee to presently existing and future indebtedness of ours or of the related guarantor, or require the holders of the notes to repay any amounts received with respect to such guarantee. In the event of a finding that a fraudulent transfer or conveyance occurred, you may not receive any repayment on the notes.

Although each guarantee will contain a provision intended to limit that guarantor's liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a fraudulent transfer, this provision may not be effective to protect those guarantees from being voided under fraudulent transfer law, or may reduce that guarantor's obligation to an amount that effectively makes its guarantee of limited value or worthless.

In a recent Florida bankruptcy case, this kind of provision was found to be unenforceable and, as a result, the subsidiary guarantees in that case were found to be fraudulent transfers. If a court were to rely on this case as precedent in litigation under the indenture, the risk that the guarantees will be found to be fraudulent transfers will be significantly increased.

Finally, as a court of equity, a bankruptcy court may subordinate the claims in respect of the notes and the guarantees to the claims of other creditors under the principle of equitable subordination if the court determines that: (1) the holder of the notes engaged in inequitable conduct to the detriment of other creditors; (2) such inequitable conduct resulted in injury to our or the applicable guarantor's other creditors or conferred an unfair advantage upon the holder of the notes; and (3) equitable subordination is not inconsistent with the provisions of applicable bankruptcy law.

***Your ability to transfer the notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will develop for the notes.***

We cannot assure you that, even following registration or exchange of the old notes for new notes, an active trading market for the notes will exist, and we will have no obligation to create such a market. At the time of the offering of the old notes, the initial purchasers advised us that they intended to make a market in the old notes and, if issued, the new notes. The initial purchasers are not obligated, however, to make a market in the old notes or the new notes and any market making may be discontinued at any time at their sole discretion. No assurance can be given as to the liquidity of or trading market for the old notes or the new notes.

The liquidity of any trading market for the notes and the market prices quoted for the notes depend upon the number of holders of the notes, the overall market for high yield securities, our financial performance or prospects or the prospects for companies in our industry generally, the interest of securities dealers in making a market in the notes and other factors.

***The market value of the notes may be subject to substantial volatility.***

Historically, the market for high-yield debt has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the notes. We cannot assure you that the market, if any, for the notes or the new notes will be free from similar disruptions or that any such disruptions will not adversely affect the prices at which you may sell your notes. As has been evident in connection with the recent turmoil in global financial markets, the entire high-yield debt market can experience sudden and sharp price swings, which can be exacerbated by factors such as (1) large or sustained sales by major investors in high-yield debt, (2) a default by a high profile issuer or (3) a change in investors' psychology regarding high-yield debt. A real or perceived economic downturn or higher interest rates could cause a decline in the market value of the notes. Moreover, if one of the major rating agencies lowers its credit rating on us or the notes, the market value of such notes will likely decline. Therefore, we cannot assure you that you will be able to sell your notes at a particular time or, in the event you are able to sell your notes, that the price that you receive will be favorable.

***Many of the covenants contained in the indenture governing the notes will be suspended if the notes are rated investment grade by both Standard & Poor's Ratings Services and Moody's Investors Service, Inc.***

Many of the covenants in the indenture governing the notes will be suspended for so long as the notes are rated investment grade by both Standard & Poor's Ratings Services and Moody's Investors Service, Inc., provided at such time no event of default under the indenture governing the notes has occurred and is continuing. These covenants will be reinstated if the rating assigned by either rating agency declines below investment grade. These covenants will restrict, among other things, our ability to pay dividends, to incur indebtedness and to enter into certain other transactions. There can be no assurance that the notes will ever be rated investment grade, or that if they are rated investment grade, that the notes will maintain such ratings. However, suspension of these covenants would allow us to engage in certain transactions that would not be permitted while these covenants were in force. See "Description of the Notes Certain Covenants Covenant Suspension."

***The guarantee of the notes by Laredo Petroleum Holdings, Inc. does not provide significant additional assurance of payment on the notes.***

The notes are guaranteed by Laredo Petroleum Holdings, Inc. However, Laredo Petroleum Holdings, Inc. is a holding company and has no operations separate from its investment in Laredo Petroleum, Inc. and Laredo Petroleum, Inc.'s subsidiaries. Therefore, if Laredo Petroleum, Inc. and the other guarantors should be unable to meet our payment obligations with respect to the notes, it is unlikely that Laredo Petroleum Holdings, Inc. would be able to do so either.

***Variable rate indebtedness subjects us to the risk of higher interest rates, which could cause our debt service obligations to increase significantly.***

Certain of our current borrowings are, and future borrowings (including borrowings under our senior secured credit facility) may be, at variable rates of interest, and, therefore, expose us to the risk of increased interest rates. If interest rates increase, our debt service obligations on our variable rate indebtedness would increase even if our outstanding indebtedness remained the same, thereby causing our net income and cash available for servicing our indebtedness to be lower than it would have been had interest rates not increased. For example, as of June 28, 2012, we had approximately $785 million of additional borrowing capacity under the 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 currently available under the 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 the effects of increased interest rates on the value of our interest rate contracts.

**Risks Related to the Exchange Offer**

***If you do not properly tender your old notes, you will continue to hold unregistered old notes and your ability to transfer old notes will remain restricted and may be adversely affected.***

The issuer will only issue new notes in exchange for old notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the old notes and you should carefully follow the instructions on how to tender your old notes. Neither we nor the exchange agent is required to tell you of any defects or irregularities with respect to your tender of old notes.

If you do not exchange your old notes for new notes pursuant to the exchange offer, the old notes you hold will continue to be subject to the existing transfer restrictions. In general, you may not offer or sell the old notes except under an exemption from, or in a transaction not subject to, the Securities

Table of Contents

Act and applicable state securities laws. We do not plan to register old notes under the Securities Act unless our registration rights agreement with the initial purchasers of the old notes requires us to do so. Further, if you continue to hold any old notes after the exchange offer is consummated, you may have trouble selling them because there will be fewer of the old notes outstanding.

***The consummation of the exchange offer may not occur.***

We are not obligated to complete the exchange offer under certain circumstances. See "Exchange Offer  Conditions to the Exchange Offer." Even if the exchange offer is completed, it may not be completed on the schedule described in this prospectus. Accordingly, holders participating in the exchange offer may have to wait longer than expected to receive their new notes, during which time those holders of old notes will not be able to effect transfers of their old notes tendered in the exchange offer.

***You may be required to deliver prospectuses and comply with other requirements in connection with any resale of the new notes.***

If you tender your old notes for the purpose of participating in a distribution of the new notes, you will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale of the new notes. In addition, if you are a broker-dealer that receives new notes for your own account in exchange for old notes that you acquired as a result of market-making activities or any other trading activities, you will be required to acknowledge that you will deliver a prospectus in connection with any resale of such new notes.

Table of Contents

## EXCHANGE OFFER

### Purpose and Effect of the Exchange Offer

At the closing of the offering of the old notes, we entered into a registration rights agreement with the initial purchasers pursuant to which we agreed, for the benefit of the holders of the old notes, at our cost, to do the following:

- file an exchange offer registration statement with the SEC with respect to the exchange offer for the new notes, and

- use commercially reasonable efforts to have the exchange offer completed by the 365th day following the date of the issuance of the notes (April 27, 2012).

We agreed to offer the new notes in exchange for surrender of the old notes upon the SEC's declaring the exchange offer registration statement effective. We agreed to use commercially reasonable efforts to cause the exchange offer registration statement to be effective continuously, and to keep the exchange offer open for a period of not less than 20 business days after the date we mail notice of the exchange offer to the holders of the old notes.

For each old note surrendered to us pursuant to the exchange offer, the holder of such old note will receive a new note having a principal amount equal to that of the surrendered old note. Interest on each new note will accrue from the last interest payment date on which interest was paid on the surrendered old note or, if no interest has been paid on such old note, from April 27, 2012. The registration rights agreement also contains agreements to include in the prospectus for the exchange offer certain information necessary to allow a broker-dealer who holds old notes that were acquired for its own account as a result of market-making activities or other trading activities (other than old notes acquired directly from us) to exchange such old notes pursuant to the exchange offer and to satisfy the prospectus delivery requirements in connection with resales of new notes received by such broker-dealer in the exchange offer. We agreed to use commercially reasonable efforts to maintain the effectiveness of the exchange offer registration statement for these purposes for a period of 180 days after the completion of the exchange offer, which period may be extended under certain circumstances.

The preceding agreement is needed because any broker-dealer who acquires old notes for its own account as a result of market-making activities or other trading activities is required to deliver a prospectus meeting the requirements of the Securities Act. This prospectus covers the offer and sale of the new notes pursuant to the exchange offer and the resale of new notes received in the exchange offer by any broker-dealer who held old notes acquired for its own account as a result of market-making activities or other trading activities other than old notes acquired directly from us or one of our affiliates.

Based on interpretations by the staff of the SEC set forth in no-action letters issued to third parties, we believe that the new notes issued pursuant to the exchange offer would in general be freely tradable after the exchange offer without further registration under the Securities Act. However, any purchaser of old notes who is an "affiliate" of ours or who intends to participate in the exchange offer for the purpose of distributing the related new notes:

- will not be able to rely on the interpretation of the staff of the SEC,

- will not be able to tender its new notes in the exchange offer, and

- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the old notes unless such sale or transfer is made pursuant to an exemption from such requirements.

Table of Contents

Each holder of the old notes (other than certain specified holders) who desires to exchange old notes for the new notes in the exchange offer will be required to make the representations described below under "Procedures for Tendering Your Representations to Us."

We further agreed to file with the SEC a shelf registration statement to register for public resale old notes held by any holder who provides us with certain information for inclusion in the shelf registration statement if:

- the exchange offer is not permitted by applicable law or SEC policy,
- the exchange offer is not for any reason completed by the 365th day following the date of the issuance of the notes (April 27, 2012), or
- prior to the completion of the exchange offer, (a) with respect to a holder of old notes that is not our or one of the guarantors' affiliates, such holder notifies us that (i) it is prohibited by applicable law or SEC policy from participating in the exchange offer, (ii) it may not resell the new notes acquired by it in the exchange offer to the public without delivering a prospectus and that the prospectus forming part of this registration statement is not appropriate or available for such resales, or (iii) it is a broker-dealer and holds old notes acquired directly from us, or (b) in the case of an initial purchaser, such initial purchaser notifies us that it will not receive freely tradable new notes in exchange for old notes constituting any portion of such initial purchaser's unsold allotment.

We have agreed to use commercially reasonable efforts to keep the shelf registration statement continuously effective until the earlier of one year following its effective date and such time as all notes covered by the shelf registration statement have been sold. We refer to this period as the "shelf effectiveness period."

The registration rights agreement provides that if the exchange offer is not completed (or, if required, the shelf registration statement is not declared effective or does not automatically become effective when required) on or before the 365th day following the date of the issuance of the notes (April 27, 2012) (or the date the shelf registration statement is required to be declared effective or automatically becomes effective, as the case may be) then additional interest shall accrue on the principal amount of the old notes at a rate of 0.25% per annum for the first 90-day period immediately following such date and by an additional 0.25% per annum with respect to each subsequent 90-day period, up to a maximum additional rate of 1.00% per annum thereafter, until the exchange offer is completed, the shelf registration statement is declared effective or, if such shelf registration statement ceased to be effective (subject to certain exceptions), again becomes effective or until the second anniversary of the issue date of the old notes, unless such period is extended, as described in the registration rights agreement.

Holders of the old notes will be required to make certain representations to us (as described in the registration rights agreement) in order to participate in the exchange offer and will be required to deliver information to be used in connection with the shelf registration statement and to provide comments on the shelf registration statement within the time periods set forth in the registration rights agreement in order to have their old notes included in the shelf registration statement.

If we effect the registered exchange offer, we will be entitled to close the registered exchange offer 20 business days after its commencement as long as we have accepted all old notes validly tendered in accordance with the terms of the exchange offer and no brokers or dealers continue to hold any old notes.

This summary of the material provisions of the registration rights agreement does not purport to be complete and is subject to, and is qualified in its entirety by reference to, all the provisions of the registration rights agreement, a copy of which is filed as an exhibit to the registration statement which includes this prospectus.

Except as set forth above, after consummation of the exchange offer, holders of old notes which are the subject of the exchange offer have no registration or exchange rights under the registration rights agreement. See " Consequences of Failure to Exchange."

**Terms of the Exchange Offer**

Subject to the terms and conditions described in this prospectus and in the letter of transmittal, we will accept for exchange any old notes properly tendered and not withdrawn prior to 5:00 p.m., New York City time, on the expiration date. We will issue new notes in principal amount equal to the principal amount of old notes surrendered in the exchange offer. Old notes may be tendered only for new notes and only in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The exchange offer is not conditioned upon any minimum aggregate principal amount of old notes being tendered for exchange.

As of the date of this prospectus, $500,000,000 in aggregate principal amount of the old notes is outstanding. This prospectus and the letter of transmittal are being sent to DTC, the sole registered holder of old notes. There will be no fixed record date for determining registered holders of old notes entitled to participate in the exchange offer.

We intend to conduct the exchange offer in accordance with the provisions of the registration rights agreement, the applicable requirements of the Securities Act and the Exchange Act and the rules and regulations of the SEC. Old notes that the holders thereof do not tender for exchange in the exchange offer will remain outstanding and continue to accrue interest. These old notes will continue to be entitled to the rights and benefits such holders have under the indenture relating to the notes.

We will be deemed to have accepted for exchange properly tendered old notes when we have given written notice of the acceptance to the exchange agent and complied with the applicable provisions of the registration rights agreement. The exchange agent will act as agent for the tendering holders for the purposes of receiving the new notes from us.

If you tender old notes in the exchange offer, you will not be required to pay brokerage commissions or fees or, subject to the letter of transmittal, transfer taxes with respect to the exchange of old notes. We will pay all charges and expenses, other than certain applicable taxes described below, in connection with the exchange offer. It is important that you read the section labeled " Fees and Expenses" for more details regarding fees and expenses incurred in the exchange offer.

We will return any old notes that we do not accept for exchange for any reason without expense to their tendering holder promptly after the expiration or termination of the exchange offer.

**Expiration Date**

The exchange offer will expire at 5:00 p.m., New York City time, on July 31, 2012, unless, in our sole discretion, we extend it.

**Extensions, Delays in Acceptance, Termination or Amendment**

We expressly reserve the right, at any time or various times, to extend the period of time during which the exchange offer is open. We may delay acceptance of any old notes by giving notice of such extension to their holders via a press release or other public announcement. During any such extensions, all old notes previously tendered will remain subject to the exchange offer, and we may accept them for exchange.

Table of Contents

If we extend the exchange offer, we will notify the exchange agent in writing of any extension. We will notify the registered holders of old notes of any such extension via a press release or other public announcement issued no later than 9:00 a.m., New York City time, on the first business day following the previously scheduled expiration date.

If any of the conditions described below under "  Conditions to the Exchange Offer" occur, we reserve the right, in our sole discretion:

- to delay accepting for exchange any old notes, or
- to extend the exchange offer, or
- to terminate the exchange offer,

by giving written notice of such delay, extension or termination to the exchange agent before 9:00 a.m., New York City time, on the first business day following the previously scheduled expiration date. Subject to the terms of the registration rights agreement, we also reserve the right to amend the terms of the exchange offer in any manner.

Any such delay in acceptance, extension, termination or amendment will be followed promptly by notice thereof via a press release or other public announcement to the registered holders of old notes. If we amend the exchange offer in a manner that we determine to constitute a material change, we will promptly disclose such amendment by means of a prospectus supplement. The supplement will be distributed to the registered holders of the old notes. Depending upon the significance of the amendment and the manner of disclosure to the registered holders, we may extend the exchange offer. In the event of a material change in the exchange offer, including the waiver by us of a material condition, we will extend the exchange offer period if necessary so that at least five business days remain in the exchange offer following notice of the material change.

**Conditions to the Exchange Offer**

We will not be required to accept for exchange, or exchange any new notes for, any old notes if the exchange offer, or the making of any exchange by a holder of old notes, would violate applicable law or any applicable interpretation of the staff of the SEC. Similarly, we may terminate the exchange offer as provided in this prospectus before accepting old notes for exchange in the event of such a potential violation.

In addition, we will not be obligated to accept for exchange the old notes of any holder that has not made to us the representations described under "  Purpose and Effect of the Exchange Offer," "  Procedures for Tendering" and "Plan of Distribution" and such other representations as may be reasonably necessary under applicable SEC rules, regulations or interpretations to allow us to use an appropriate form to register the new notes under the Securities Act.

In addition, we will not accept for exchange any old notes tendered, and will not issue new notes in exchange for any such old notes, if at such time any stop order has been threatened or is in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the indenture relating to the notes under the Trust Indenture Act of 1939.

We expressly reserve the right to amend or terminate the exchange offer, and to reject for exchange any old notes not previously accepted for exchange, upon the occurrence of any of the conditions to the exchange offer specified above. We will give prompt written notice of any extension, amendment, non-acceptance or termination to the exchange agent.

These conditions are for our sole benefit, and we may assert them or waive them in whole or in part at any time or at various times in our sole discretion. If we fail at any time to exercise any of these rights, this failure will not mean that we have waived our rights. Each such right will be deemed an

Table of Contents

ongoing right that we may assert at any time or at various times prior to expiration of the exchange offer.

**Procedures for Tendering**

In order to participate in the exchange offer, you must properly tender your old notes to the exchange agent as described below. We will only issue new notes in exchange for old notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the old notes, and you should follow carefully the instructions on how to tender your old notes. It is your responsibility to properly tender your old notes. We have the right to waive any defects. However, we are not required to waive defects and neither we nor the exchange agent are required to notify you of defects in your tender.

If you have any questions or need help in exchanging your notes, please call the exchange agent, whose contact information is set forth in "Prospectus Summary The Exchange Offer Exchange Agent."

All of the old notes were issued in book-entry form, and all of the old notes are currently represented by global certificates held for the account of DTC. We have confirmed with DTC that the old notes may be tendered using the Automated Tender Offer Program ("ATOP") instituted by DTC. The exchange agent will establish an account with DTC for purposes of the exchange offer promptly after the commencement of the exchange offer and DTC participants may electronically transmit their acceptance of the exchange offer by causing DTC to transfer their old notes to the exchange agent using the ATOP procedures. In connection with the transfer, DTC will send an "agent's message" to the exchange agent. The agent's message will state that DTC has received instructions from the participant to tender old notes and that the participant agrees to be bound by the terms of the letter of transmittal.

By using the ATOP procedures to exchange old notes, you will not be required to deliver a letter of transmittal to the exchange agent. However, you will be bound by its terms just as if you had signed it.

There is no procedure for guaranteed late delivery of the notes.

***Determinations Under the Exchange Offer***

We will determine in our sole discretion all questions as to the validity, form, eligibility, time of receipt, acceptance of tendered old notes and withdrawal of tendered old notes. Our determination will be final and binding. We reserve the absolute right to reject any old notes not properly tendered or any old notes our acceptance of which would, in the opinion of our counsel, be unlawful. We also reserve the right to waive any defect, irregularities or conditions of tender as to particular old notes. Our interpretation of the terms and conditions of the exchange offer, including the instructions in the letter of transmittal, will be final and binding on all parties. Unless waived, all defects or irregularities in connection with tenders of old notes must be cured within such time as we shall determine. Although we intend to notify holders of defects or irregularities with respect to tenders of old notes, neither we, the exchange agent nor any other person will incur any liability for failure to give such notification. Tenders of old notes will not be deemed made until such defects or irregularities have been cured or waived. Any old notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned to the tendering holder, unless otherwise provided in the letter of transmittal, promptly following the expiration date.

Table of Contents

***When We Will Issue New Notes***

In all cases, we will issue new notes for old notes that we have accepted for exchange under the exchange offer only after the exchange agent timely receives prior to 5:00 p.m., New York City time, on the expiration date:

- a book-entry confirmation of such old notes into the exchange agent's account at DTC; and
- a properly transmitted agent's message.

Such new notes will be issued promptly following the expiration or termination of the offer.

***Return of Old Notes Not Accepted or Exchanged***

If we do not accept any tendered old notes for exchange or if old notes are submitted for a greater principal amount than the holder desires to exchange, the unaccepted or non-exchanged old notes will be returned without expense to their tendering holder. Such non-exchanged old notes will be credited to an account maintained with DTC. These actions will occur promptly after the expiration or termination of the exchange offer.

***Your Representations to Us***

By agreeing to be bound by the letter of transmittal, you will represent to us that, among other things:

- any new notes that you receive will be acquired in the ordinary course of your business;
- you have no arrangement or understanding with any person or entity to participate in the distribution of the old notes or the new notes within the meaning of the Securities Act;
- you are not our "affiliate," as defined in Rule 405 of the Securities Act;
- if you are not a broker-dealer, you are not engaged in and do not intend to engage in the distribution of the new notes; and
- if you are a broker-dealer that will receive new notes for your own account in exchange for old notes, you acquired those notes as a result of market-making activities or other trading activities and you will deliver a prospectus (or to the extent permitted by law, make available a prospectus) in connection with any resale of such new notes.

**Withdrawal of Tenders**

Except as otherwise provided in this prospectus, you may withdraw your tender at any time prior to 5:00 p.m., New York City time, on the expiration date. For a withdrawal to be effective you must comply with the appropriate procedures of DTC's ATOP system. Any notice of withdrawal must specify the name and number of the account at DTC to be credited with withdrawn old notes and otherwise comply with the procedures of DTC.

We will determine all questions as to the validity, form, eligibility and time of receipt of notice of withdrawal. Our determination shall be final and binding on all parties. We will deem any old notes so withdrawn not to have been validly tendered for exchange for purposes of the exchange offer.

Any old notes that have been tendered for exchange but are not exchanged for any reason will be credited to an account maintained with DTC for the old notes. This crediting will take place as soon as practicable after withdrawal, rejection of tender or termination of the exchange offer. You may retender properly withdrawn old notes by following the procedures described under " Procedures for Tendering" above at any time prior to 5:00 p.m., New York City time, on the expiration date.

Table of Contents

**Fees and Expenses**

We will bear the expenses of soliciting tenders. The principal solicitation is being made by mail; however, we may make additional solicitation by facsimile, telephone, electronic mail or in person by our officers and regular employees and those of our affiliates.

We have not retained any dealer-manager in connection with the exchange offer and will not make any payments to broker-dealers or others soliciting acceptances of the exchange offer. We will, however, pay the exchange agent reasonable and customary fees for its services and reimburse it for its related reasonable out-of-pocket expenses.

We will pay the cash expenses to be incurred in connection with the exchange offer. They include:

- all registration and filing fees and expenses;
- all fees and expenses of compliance with federal securities and state "blue sky" or securities laws;
- accounting fees, legal fees incurred by us, disbursements and printing, messenger and delivery services, and telephone costs; and
- related fees and expenses.

**Transfer Taxes**

We will pay all transfer taxes, if any, applicable to the exchange of old notes under the exchange offer. The tendering holder, however, will be required to pay any transfer taxes, whether imposed on the registered holder or any other person, if a transfer tax is imposed for any reason other than the exchange of old notes under the exchange offer.

**Consequences of Failure to Exchange**

If you do not exchange new notes for your old notes under the exchange offer, you will remain subject to the existing restrictions on transfer of the old notes. In general, you may not offer or sell the old notes unless the offer or sale is either registered under the Securities Act or exempt from registration under the Securities Act and applicable state securities laws. Except as required by the registration rights agreement, we do not intend to register resales of the old notes under the Securities Act.

**Accounting Treatment**

We will record the new notes in our accounting records at the same carrying value as the old notes. This carrying value is the aggregate principal amount of the old notes less any bond discount or plus any bond premium, as reflected in our accounting records on the date of exchange. Accordingly, we will not recognize any gain or loss for accounting purposes in connection with the exchange offer.

**Other**

Participation in the exchange offer is voluntary, and you should carefully consider whether to accept. You are urged to consult your financial and tax advisors in making your own decision on what action to take.

We may in the future seek to acquire untendered old notes in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any old notes that are not tendered in the exchange offer or to file a registration statement to permit resales of any untendered old notes.

## RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our ratio of earnings to fixed charges for the periods presented:

| | For the three months ended March 31, | | For the years ended December 31, | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Pro forma 2012 | 2012 | Pro forma 2011 | 2011 | 2010 | 2009 | 2008 | 2007 |
| Ratio of earnings to fixed charges(1) | 2.3x(2) | 3.6x | 2.4x(3) | 4.2x | 4.2x | (4) | (4) | (4) |

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of pretax income (loss) plus fixed charges less interest capitalized. "Fixed charges" represents interest incurred, amortization of deferred debt offering costs and that portion of rental expense on operating leases deemed to be the equivalent of interest.

(2) Because the net proceeds of the old notes were used to repay indebtedness, the pro forma impact on the amount of fixed charges causes our earnings to cover fixed charges to change by greater than 10% for the three months ended March 31, 2012. At March 31, 2012, we had approximately $230.0 million of borrowings outstanding under our senior secured credit facility and $550.0 million in 2019 senior notes. The weighted average interest rate paid on amounts outstanding under our senior secured credit facility for the three months ended March 31, 2012 was 0.55% and under the 2019 senior notes was 2.37% (excluding the impact of our interest rate swaps).

(3) Because the net proceeds of the offering of the old notes were used to repay indebtedness, the pro forma impact on the amount of fixed charges causes our earnings to cover fixed charges to change by greater than 10% for the year ended December 31, 2011. At December 31, 2011, we had approximately $85.0 million of borrowings outstanding under our senior secured credit facility and $550.0 million in 2019 senior notes. For the year ended December 31, 2011, the weighted average interest rates paid on amounts outstanding under our senior secured credit facility, the term loan, the Broad Oak credit facility and the 2019 senior notes was 2.07%, 0.51%, 3.07% and 8.98% (excluding the impact of our interest rate swaps).

(4) Due to our net operating losses for each of the years ended December 31, 2009, 2008 and 2007, the respective ratios of coverage were less than 1:1. To achieve the ratio coverage of 1:1, we would have needed additional earnings of approximately $258.5 million, $245.8 million, and $7.5 million, respectively.

Table of Contents

## USE OF PROCEEDS

The exchange offer is intended to satisfy our obligations under the registration rights agreement. We will not receive any proceeds from the issuance of the new notes in the exchange offer. In consideration for issuing the new notes as contemplated by this prospectus, we will receive old notes in a like principal amount. The form and terms of the new notes are identical in all respects to the form and terms of the old notes, except the new notes will be registered under the Securities Act and will not contain restrictions on transfer, registration rights or provisions for additional interest. Old notes surrendered in exchange for the new notes will be retired and cancelled and will not be reissued. Accordingly, the issuance of the new notes will not result in any change in our outstanding indebtedness.

Table of Contents

## 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 three months ended March 31, 2012 and 2011 and the consolidated balance sheet as of March 31, 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 three months ended March 31, 2012 | 2011 | For the years ended December 31, 2011 | 2010 | 2009 | 2008(1) | 2007(2) |
|---|---|---|---|---|---|---|---|
| | (unaudited) | | | | | | (unaudited) |
| Statement of operations data: | | | | | | | |
| Total revenues | $ 150,348 | $ 107,111 | $ 510,270 | $ 242,000 | $ 96,574 | $ 74,187 | $ 9,628 |
| Total costs and expenses | 94,959 | 57,949 | 308,371 | 169,018 | 350,103 | 350,653 | 17,251 |
| Operating income (loss) | 55,389 | 49,162 | 201,899 | 72,982 | (253,529) | (276,466) | (7,623) |
| Non-operating income (expense), net | (14,397) | (41,895) | (36,971) | (12,546) | (4,972) | 30,702 | 167 |
| Income (loss) before income taxes | 40,992 | 7,267 | 164,928 | 60,436 | (258,501) | (245,764) | (7,456) |
| Net income (loss) | 26,235 | 4,670 | 105,554 | 86,248 | (184,495) | (192,047) | (6,051) |
| Pro forma net income per common share: | | | | | | | |
| Basic | $ 0.21 | | $ 0.98 | | | | |
| Diluted | $ 0.20 | | $ 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.

Table of Contents

| (in thousands) | As of March 31, 2012 (unaudited) | As of December 31, 2011 | 2010 | 2009 | 2008 | 2007 (unaudited) |
|---|---|---|---|---|---|---|
| Balance sheet data: | | | | | | |
| Cash and cash equivalents | $ 12,212 | $ 28,002 | $ 31,235 | $ 14,987 | $ 13,512 | $ 6,937 |
| Net property and equipment | 1,556,449 | 1,378,509 | 809,893 | 396,100 | 350,702 | 137,852 |
| Total assets | 1,798,482 | 1,627,652 | 1,068,160 | 625,344 | 578,387 | 171,799 |
| Current liabilities | 205,948 | 214,361 | 150,243 | 79,265 | 101,864 | 16,809 |
| Long-term debt | 781,913 | 636,961 | 491,600 | 247,100 | 148,600 | 44,500 |
| Stockholders'/ unit holders' equity | 788,495 | 760,013 | 411,099 | 289,107 | 318,364 | 109,707 |

| (in thousands) | For the three months ended March 31, 2012 (unaudited) | 2011 (unaudited) | For the years ended December 31, 2011 | 2010 | 2009 | 2008 | 2007 (unaudited) |
|---|---|---|---|---|---|---|---|
| Other financial data: | | | | | | | |
| Net cash provided by operating activities | $ 91,402 | $ 75,988 | $ 344,076 | $ 157,043 | $ 112,669 | $ 25,332 | $ 5,019 |
| Net cash used in investing activities | (252,192) | (192,360) | (706,787) | (460,547) | (361,333) | (490,897) | (131,153) |
| Net cash provided by financing activities | 145,000 | 100,890 | 359,478 | 319,752 | 250,139 | 472,140 | 126,726 |

| (in thousands, unaudited) | For the three months ended March 31, 2012 | 2011 | For the years ended December 31, 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|---|---|
| Adjusted EBITDA(1) | $ 113,883 | $ 82,854 | $ 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, capital expenditures and working capital, income taxes, franchise taxes and other

Table of Contents

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:

| (in thousands, unaudited) | For the three months ended March 31, 2012 | 2011 | For the years ended December 31, 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|---|---|
| Net income (loss) | $ 26,235 | $ 4,670 | $ 105,554 | $ 86,248 | $ (184,495) | $ (192,047) | $ (6,051) |
| Plus: | | | | | | | |
| Interest expense | 14,684 | 10,516 | 50,580 | 18,482 | 7,464 | 4,410 | 2,046 |
| Depreciation, depletion and amortization | 51,523 | 32,478 | 176,366 | 97,411 | 58,005 | 33,102 | 4,986 |
| Impairment of long-lived assets | | 206 | 243 | | 246,669 | 282,587 | |
| Write-off of deferred loan costs | | 3,246 | 6,195 | | | | |
| Loss on disposal of assets | | 17 | 40 | 30 | 85 | 2 | |
| Unrealized losses (gains) on derivative financial instruments | 3,334 | 27,504 | (20,890) | 11,648 | 46,003 | (27,174) | (1,098) |
| Realized losses on interest rate derivatives | 1,103 | 1,301 | 4,873 | 5,238 | 3,764 | 278 | |
| Non-cash equity and stock-based compensation | 2,247 | 319 | 6,111 | 1,257 | 1,419 | 1,864 | |
| Income tax expense (benefit) | 14,757 | 2,597 | 59,374 | (25,812) | (74,006) | (53,717) | (1,405) |
| Adjusted EBITDA | $ 113,883 | $ 82,854 | $ 388,446 | $ 194,502 | $ 104,908 | $ 49,305 | $ (1,522) |

Table of Contents

## 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 "Cautionary Statement Regarding Forward-Looking Statements" on page ii of this prospectus and "Risk Factors" in the 2011 Annual Report and the Quarterly Report, which are incorporated by reference into this prospectus.*

### Overview

We are an independent energy company focused on the exploration, development and acquisition of oil and natural gas properties 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 three months ended March 31, 2012 included the following:

- Oil and natural gas sales of approximately $149.0 million, compared to approximately $105.8 million for the three months ended March 31, 2011;
- Average daily production of 27,995 BOE/D, compared to 21,048 BOE/D for the three months ended March 31, 2011 and 26,270 BOE/D for the three months ended December 31, 2011; and
- Adjusted EBITDA (a non-GAAP financial measure) of $113.9 million compared to $82.9 million for the three months ended March 31, 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. We have historically developed properties that we believe will meet or exceed our rate of return criteria. For acquisitions of properties with additional development and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. We also make acquisitions in core, mature areas where management can leverage knowledge and experience to identify upsides in assets.

Table of Contents

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.

**Core Areas of Operations**

Our activities are primarily focused in the Wolfberry and deeper horizons of the Permian Basin in West Texas and the Anadarko Granite Wash in the Texas Panhandle and Western Oklahoma. The oil and liquids-rich Permian Basin and the liquids-rich Anadarko Granite Wash are characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and significant initial production rates. As of March 31, 2012, we had an interest in 1,212 gross producing wells.

Additionally, as of March 31, 2012, we have accumulated 378,420 net acres. Through December 31, 2011, we have identified over 6,000 gross potential drilling locations on our existing acreage. We intend to continue to explore and develop this large acreage position to increase our cash flow, production and reserves through continued vertical and horizontal drilling programs.

**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 gas reserves. From the year ended December 31, 2009 through the three months ended March 31, 2012, West Texas Intermediate Light Sweet Crude Oil prices have been in a range between $39.00 and $110.00 per Bbl and the NYMEX Henry Hub spot prices have been in a range between $1.98 and $2.98 per MMBtu.

The unweighted arithmetic average first-day-of-the-month index prices for the prior 12 months used to value our reserves were $94.65 per Bbl for oil and $3.58 per MMBtu for natural gas at March 31, 2012, and $80.04 per Bbl for oil and $3.89 per MMBtu for natural gas at March 31, 2011. 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. 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.

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 such reserve estimates we calculated for Broad Oak, we believe the legacy Laredo properties represented 92% of such combined proved reserves at year end 2009. 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 three months ended March 31, 2012, our revenues are comprised of sales of approximately 69% oil, 30% gas and 1% for transportation, gathering, drilling and production. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

**Hedging**

Due to the inherent volatility in oil and 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 gas production. By removing a majority of the price volatility associated with future production, we expect to reduce, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. We have not elected hedge accounting on these derivatives and, therefore, the unrealized gains and losses on open positions are reflected 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 three months ended March 31, 2012 and 2011, we recognized unrealized losses on commodity derivatives, based on market price fluctuations compared to prices in our commodity derivative contracts. During the year ended December 31, 2011, we recognized an unrealized gain on commodity derivatives, as market prices generally decreased compared to our derivative contract prices. During the years ended December 31, 2010 and 2009, we recognized unrealized losses as market prices generally increased compared to our derivative contract prices during these periods.

Subsequent to March 31, 2012, we entered into two additional derivative contracts to hedge the price risk associated with approximately 180,000 and 96,000 barrels of our oil production for the twelve months ending December 31, 2014 and 2015, respectively. These derivative contracts have associated

Table of Contents

deferred premiums totaling approximately $2.0 million. See Note N to our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding these derivative contracts.

Our open hedging positions as of March 31, 2012 are as follows:

| | Remaining Year 2012 | Year 2013 | Year 2014 | Year 2015 | Total |
|---|---|---|---|---|---|
| ***Oil(1)*** | | | | | |
| Total volume hedged with ceiling price (Bbls) | 1,453,500 | 1,368,000 | 726,000 | 252,000 | 3,799,500 |
| Weighted average ceiling price ($/Bbl) | $ 108.81 | $ 110.55 | $ 129.09 | $ 135.00 | $ 115.05 |
| Total volume hedged with floor price (Bbls) | 1,957,500 | 2,448,000 | 1,086,000 | 612,000 | 6,103,500 |
| Weighted average floor price ($/Bbl) | $ 79.90 | $ 77.19 | $ 75.30 | $ 75.00 | $ 77.50 |
| ***Natural Gas(2)*** | | | | | |
| Total volume hedged with ceiling price (MMBtu) | 7,810,000 | 7,300,000 | 6,960,000 | | 22,070,000 |
| Weighted average ceiling price ($/MMBtu) | $ 5.57 | $ 6.75 | $ 7.03 | $ | $ 6.42 |
| Total volume hedged with floor price (MMBtu) | 11,050,000 | 13,900,000 | 6,960,000 | | 31,910,000 |
| Weighted average floor price ($/MMBtu) | $ 4.63 | $ 3.96 | $ 4.00 | $ | $ 4.20 |
| ***Natural Gas basis swaps (MMbtu)*** | | | | | |
| Total volume hedged (MMBtu) | 2,160,000 | 1,200,000 | | | 3,360,000 |
| Weighted average price ($/MMBtu) | $ 0.31 | $ 0.33 | $ | $ | $ 0.31 |

(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 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 gas futures and the West Texas WAHA index gas price.

**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.

*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.

Table of Contents

*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.

*Realized and unrealized gain (loss) on interest rate derivative instruments.* We utilize interest rate swaps and caps to reduce our exposure to fluctuations in interest rates on our outstanding debt. This amount represents (i) the recognition of unrealized gains and losses associated with our open interest rate derivative contracts as interest rates change and interest rate contracts expire or new ones are entered into, and (ii) our realized gains and losses on the settlement of these interest rate contracts. We classify these gains and losses as operating activities in our consolidated statements of cash flows.

*Interest expense.* We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our senior secured credit facility, our senior unsecured notes and, prior to its termination on July 1, 2011, the Broad Oak credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We have entered into various interest rate derivative contracts to mitigate the effects of interest rate changes. We do not designate these derivative contracts as hedges and therefore hedge accounting treatment is not applicable. Realized and unrealized gains or losses on these interest rate contracts are included in non-operating income (expense) as discussed above. We reflect interest paid to the lenders and bondholders in interest expense. In addition, we include the amortization of deferred financing costs

Table of Contents

(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.

Table of Contents

**Results of Operations**

***Three months ended March 31, 2012 as compared to the three months ended March 31, 2011***

The following table sets forth selected operating data for the three months ended March 31, 2012 compared to the three months ended March 31, 2011:

| (in thousands except for production data and average sales prices) | Three months ended March 31, 2012 | Three months ended March 31, 2011 |
|---|---|---|
| Operating results: | | |
| Revenues | | |
| Oil | $ 104,067 | $ 63,864 |
| Natural gas | 44,884 | 41,905 |
| Natural gas transportation and treating | 1,397 | 1,342 |
| Total revenues | 150,348 | 107,111 |
| Costs and expenses | | |
| Lease operating expenses | 14,984 | 7,918 |
| Production and ad valorem taxes | 8,919 | 7,102 |
| Natural gas transportation and treating | 300 | 552 |
| Drilling and production | 1,438 | 296 |
| General and administrative | 15,284 | 8,929 |
| Stock-based compensation | 2,247 | 319 |
| Accretion of asset retirement obligations | 264 | 149 |
| Depreciation, depletion and amortization | 51,523 | 32,478 |
| Impairment expense | | 206 |
| Total costs and expenses | 94,959 | 57,949 |
| Non-operating income (expense): | | |
| Realized and unrealized gain (loss): | | |
| Commodity derivative financial instruments, net | 594 | (28,034) |
| Interest rate derivatives, net | (323) | (118) |
| Interest expense | (14,684) | (10,516) |
| Interest and other income | 16 | 36 |
| Write-off of deferred loan costs | | (3,246) |
| Loss on disposal of assets | | (17) |
| Non-operating expense, net | (14,397) | (41,895) |
| Income tax expense | (14,757) | (2,597) |
| Net income | $ 26,235 | $ 4,670 |
| Production data: | | |
| Oil (MBbls) | 1,067 | 709 |
| Natural gas (MMcf) | 8,882 | 7,112 |
| Barrels of oil equivalent(1)(3) (MBOE) | 2,548 | 1,894 |
| Average daily production(3) (BOE/D) | 27,995 | 21,048 |
| Average sales prices: | | |
| Oil, realized ($/Bbl) | $ 97.53 | $ 90.08 |
| Oil, hedged(2) ($/Bbl) | $ 95.37 | $ 86.78 |
| Natural gas, realized ($/Mcf) | $ 5.05 | $ 5.89 |
| Natural gas, hedged(2) ($/Mcf) | $ 5.84 | $ 6.31 |

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

42

Table of Contents

(2) Hedged prices reflect the after-effect of our commodity hedging transactions on our average sales prices. Our calculation of such after-effect includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting.

(3) The volumes presented for the three months ended March 31, 2012 and March 31, 2011 are based on actual results and are not calculated using the rounded numbers in the table above.

*Oil and gas revenues.* Our oil and gas revenues increased by approximately $43.2 million, or 41%, to $149.0 million during the three months ended March 31, 2012 as compared to the three months ended March 31, 2011. 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 6,947 BOE/D during the three months ended March 31, 2012 as compared to the same period in 2011. The total increase in revenue of approximately $43.2 million is largely attributable to higher oil and gas production volumes for the three months ended March 31, 2012 as compared to the three months ended March 31, 2011. Production increased by 358 MBbls for oil and 1,770 MMcf for gas for the three months ended March 31, 2012 as compared to the three months ended March 31, 2011. The net dollar effect of the increase in prices of approximately $0.5 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 $42.7 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 3/31/2012(2) | Total net dollar effect of change (in thousands) |
|---|---|---|---|
| Effect of changes in price: | | | |
| Oil | $ 7.45 | 1,067 | $ 7,949 |
| Natural gas | $ (0.84) | 8,882 | $ (7,461) |
| Total revenues due to change in price | | | $ 488 |

| | Change in production volumes(2) | Prices at 3/31/2011(1) | Total net dollar effect of change (in thousands) |
|---|---|---|---|
| Effect of changes in volumes: | | | |
| Oil | 358 | $ 90.08 | $ 32,249 |
| Natural gas | 1,770 | $ 5.89 | $ 10,425 |
| Total revenues due to change in volumes | | | $ 42,674 |
| Rounding differences | | | $ 20 |
| Total change in revenues | | | $ 43,182 |

(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 $15.0 million for the three months ended March 31, 2012 from $7.9 million for the three months ended March 31, 2011, an increase of approximately 90%. The increase was primarily due to an increase in drilling activity, which resulted in additional producing wells during the first three months of 2012 compared to 2011. Additionally, a portion of the increase is due to approximately $2.0 million in additional workover expenses incurred during 2012 as compared to the same period in 2011 resulting

Table of Contents

largely from costs of approximately $1.6 million 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 $5.88 per BOE at March 31, 2012 from $4.18 per BOE at March 31, 2011. Excluding the one-time workover expense noted above, lease operating expense per BOE at March 31, 2012 is $5.25 per BOE.

*Production and ad valorem taxes.* Production and ad valorem taxes increased to approximately $8.9 million for the three months ended March 31, 2012 from $7.1 million for the three months ended March 31, 2011, an increase of $1.8 million. This increase was primarily due to the increase in market prices for oil, which were partially offset by a decrease in the market prices for gas, as well as a significant increase in production for the first quarter of 2012 as compared to the same period in 2011. The average realized prices excluding derivatives for the three months ended March 31, 2012 were $97.53 per Bbl for oil and $5.05 per Mcf for gas as compared to $90.08 per Bbl for oil and $5.89 per Mcf for gas for the three months ended March 31, 2011.

*Drilling and production.* Drilling and production costs increased to approximately $1.4 million for the three months ended March 31, 2012 from $0.3 million for the three months ended March 31, 2011 as a result of increased maintenance costs related to the increase in drilling during the first three months of 2012 as compared to the same period in 2011.

*General and administrative ("G&A").* G&A expense increased to approximately $15.3 million for the three months ended March 31, 2012 from $8.9 million for the same period in 2011, an increase of $6.4 million, or 72%. Increases in salaries, benefits and bonuses accounted for approximately $4.1 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. Professional fees increased by approximately $0.9 million due largely to fees incurred for the preparation and filing of the 2011 Annual Report and proxy materials as a new public reporting company. Additionally, compensation expense related to the issuance of our performance unit liability awards in February 2012 accounted for approximately $0.5 million of the total change. On a per-BOE basis, G&A expense increased to $6.00 per BOE during the three months ended March 31, 2012 from $4.71 per BOE at March 31, 2011.

*Stock-based compensation.* Stock-based compensation increased to approximately $2.2 million for the three months ended March 31, 2012 from $0.3 million for the same period in 2011, an increase of approximately $1.9 million. This increase is due to the issuance of 605,287 restricted stock awards and 602,948 non-qualified restricted stock options to employees in February 2012. The fair value of the restricted stock awards issued during the first quarter of 2012 was calculated based on the value of our stock price on the date of grant in accordance with the applicable 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. See Note D to our unaudited consolidated financial statements included elsewhere in this prospectus for additional information regarding our stock-based compensation.

*Depreciation, depletion and amortization ("DD&A").* DD&A increased to approximately $51.5 million for the three months ended March 31, 2012 from $32.5 million for the same period in

Table of Contents

2011, an increase of $19.0 million, or 59%. The following table provides components of our DD&A expense for the three months ended March 31, 2012 and 2011.

| (in thousands except for per BOE data) | Three months ended March 31, 2012 | Three months ended March 31, 2011 |
|---|---|---|
| Depletion of proved oil and natural gas properties | $ 50,067 | $ 31,431 |
| Depreciation of pipeline assets | 733 | 556 |
| Depreciation of other property and equipment | 723 | 491 |
| Total depletion, depreciation and amortization | $ 51,523 | $ 32,478 |
| Depletion of proved oil and natural gas properties per BOE | $ 19.65 | $ 16.59 |

The increase in depletion of proved oil and natural gas properties of $18.6 million and the increase in the depletion rate of $3.06 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 2012 and (iv) a corresponding offset caused by the increase in oil prices and the decrease in natural gas prices between periods used to calculate proved reserves.

*Impairment expense.* Impairment expense decreased to zero for the three months ended March 31, 2012 from $0.2 million for the three months ended March 31, 2011. Impairment expense incurred in the first quarter of 2011 was to reflect our materials and supplies inventory at the lower of cost or market value calculated as of March 31, 2011. It was determined at March 31, 2012 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 the estimated fair value. At March 31, 2012 and 2011, 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 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 three months ended March 31, 2012 and 2011, our commodity derivatives resulted in realized gains of $4.7 million and $0.7 million, respectively. For the three months ended March 31, 2012 and 2011, our commodity derivatives resulted in unrealized losses of $4.1 million and $28.7 million, respectively. At March 31, 2012, we had 16 commodity derivatives contracts with associated deferred premiums totaling approximately $25.5 million. The estimated fair value of our total deferred premiums was approximately $23.1 million at March 31, 2012. The fair market value of these premiums is deducted from our unrealized gain or loss at each period end and lead to the overall unrealized loss of $4.1 million for the three months ended March 31, 2012 as noted above.

*Interest expense and realized and unrealized gains and losses on interest rate swaps.* Interest expense increased to approximately $14.7 million for the three months ended March 31, 2012 from $10.5 million for the three months ended March 31, 2011, largely due to the issuance of our $9^1/_2$% senior unsecured notes due in 2019 during January and October of 2011 as shown in the table below. Additionally, we had approximately $0.9 million in amortized deferred loan costs and $0.1 million in deferred option premium and deferred senior notes premium amortization that were charged to interest expense for the three months ended March 31, 2012 as compared to $0.9 million in amortized deferred loan costs and

Table of Contents

$0.3 million in other interest expense, fees and deferred option premium amortization for the three months ended March 31, 2011. For the three months ended March 31, 2012, we capitalized approximately $0.4 million in interest costs related to capital expenditures on undeveloped properties compared to zero capitalized interest for the three months ended March 31, 2011.

| | Three months ended March 31, 2012 | | Three months ended March 31, 2011 | |
|---|---|---|---|---|
| (in thousands except for percentages) | Weighted average principal | Weighted average interest rate(3) | Weighted average principal | Weighted average interest rate(3) |
| Senior secured credit facility | $ 167,198 | 0.55% | $ 177,500 | 0.20% |
| 2019 senior notes | 550,000 | 2.37% | 350,000 | 1.85% |
| Term loan(1) | | | 100,000 | 0.51% |
| Broad Oak credit facility(2) | | | 58,363 | 3.29% |

(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 March 31, 2012, 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 March 31, 2011, 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 $1.1 million and $1.3 million for the three months ended March 31, 2012 and 2011, respectively. Additionally, we recorded unrealized gains on interest rate swaps of $0.8 million and $1.2 million for the three months ended March 31, 2012 and March 31, 2011, respectively. At March 31, 2012, the estimated fair value of our interest rate swaps was in a net liability position of $1.2 million compared to $2.0 million at December 31, 2011.

*Write-off of deferred loan costs.* In January 2011, we used a portion of the net proceeds of the issuance of the 2019 senior notes to pay in full and retire our term loan. Additionally, concurrent with the issuance of the 2019 senior notes, the borrowing base on our senior secured credit facility during January 2011 was lowered from $220.0 million to $200.0 million. As a result, we took a charge to expense for the debt issuance costs attributable to our term loan and a proportionate percentage of the costs incurred for our senior secured credit facility, which totaled $2.9 million and $0.3 million, respectively.

*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 $14.8 million for the three months ended March 31, 2012, compared to a deferred income tax expense of $2.6 million for the three months ended March 31, 2011. The estimated annual effective tax rate was 36% for the three months ended March 31, 2012 and 2011, respectively. 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.

Table of Contents

***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:

| **(in thousands except for production data and average sales prices)** | **Years ended December 31, 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 | 44,953 | 29,651 |
| Equity and stock-based compensation | 6,111 | 1,257 |
| 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 |
| Production data: | | |
| Oil (MBbls) | 3,368 | 1,648 |
| Natural gas (MMcf) | 31,711 | 21,381 |
| Barrels of oil equivalent(1)(3) (MBOE) | 8,654 | 5,212 |
| Average daily production(3) (BOE/D) | 23,709 | 14,278 |
| Average sales prices: | | |
| Oil, realized ($/Bbl) | $ 91.00 | $ 77.00 |
| Oil, hedged(2) ($/Bbl) | $ 88.62 | $ 77.26 |
| Natural gas, realized ($/Mcf) | $ 6.30 | $ 5.28 |
| Natural gas, hedged(2) ($/Mcf) | $ 6.67 | $ 6.32 |

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

Table of Contents

(2)
Hedged prices reflect the after-effect of our commodity hedging transactions on our average sales prices. Our calculation of such after-effect includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting.

(3)
The volumes presented for the year ended December 31, 2011 are based on actual results and are not calculated using the rounded numbers in the table above.

*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, 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.

Table of Contents

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

*Equity and stock-based compensation.* 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.

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

Table of Contents

future periods. See Note O to our audited consolidated financial statements included elsewhere in this prospectus for additional information.

*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, | |
|---|---|---|
| | **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 |

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 $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

Table of Contents

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 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.

| | Year ended December 31, 2011 | | Year ended December 31, 2010 | |
|---|---|---|---|---|
| **(in thousands except for percentages)** | **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 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 $5.5 million at December 31, 2010.

*Write-off of deferred loan costs.* In January 2011, we used a portion of the net proceeds of the issuance of the 2019 senior notes to pay in full and retire our term loan. Additionally, concurrent with the issuance of the 2019 senior notes, the borrowing base on our senior secured credit facility was lowered from $220.0 million to $200.0 million. As a result, we took a charge to expense for the debt issuance costs attributable to our term loan and a proportionate percentage of the costs incurred for our senior secured credit facility, which totaled $2.9 million and $0.3 million, respectively. As of December 31, 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.

Table of Contents

*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.

Table of Contents

***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:

| (in thousands except for production data and average sales prices) | Years ended December 31, 2010 | Years ended December 31, 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 | 29,651 | 21,164 |
| Equity and stock-based compensation | 1,257 | 1,419 |
| 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) |
| Production data: | | |
| Oil (MBbls) | 1,648 | 513 |
| Natural gas (MMcf) | 21,381 | 18,302 |
| Barrels of oil equivalent(1) (MBOE) | 5,212 | 3,563 |
| Average daily production (BOE/D) | 14,278 | 9,762 |
| Average sales prices: | | |
| Oil, realized ($/Bbl) | $ 77.00 | $ 58.37 |
| Oil, hedged(2) ($/Bbl) | $ 77.26 | $ 65.42 |
| Natural gas, realized ($/Mcf) | $ 5.28 | $ 3.52 |
| Natural gas, hedged(2) ($/Mcf) | $ 6.32 | $ 6.17 |

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

(2)

Hedged prices reflect the after-effect of our commodity hedging transactions on our average sales prices. Our calculation of such after-effect includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting.

Table of Contents

*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 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 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.

Table of Contents

*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 $29.7 million at December 31, 2010 from $21.2 million at December 31, 2009, an increase of $8.5 million, or 40%. 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. 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 $5.69 per BOE during the year ended December 31, 2010 from $5.94 per BOE at December 31, 2009. This decrease was a result of a larger overall increase in production volumes between the two periods.

*Equity and stock-based compensation.* 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.

*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, 2011 and 2010.

| | 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 |

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.

Table of Contents

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.

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 and, 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 due 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

Table of Contents

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.

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 $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

Table of Contents

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 affiliates of Warburg Pincus LLC, certain members of our management and our board of directors, borrowings under our senior secured credit facility, the 2019 senior notes, the old notes, borrowings under the prior Broad Oak credit facility, borrowings under our prior term loan 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 continually monitor market conditions and may consider taking on additional debt, which may be in the form of bank debt, debt securities or other sources of financing. We cannot assure you that we will take on any such debt or what the terms of such debt would be. We believe that we have significant liquidity available to us from cash flow from operations and under our senior secured credit facility as well as the remaining proceeds from the April 2012 offering of $500.0 million in old notes for our planned exploration and development activities. As of May 31, 2012, we had approximately $199.9 million in cash on hand. In addition, our hedge positions currently provide relative certainty on a majority of our cash flows from operations through 2012 even with the general decline in the prices of natural gas.

At March 31, 2012, we had approximately $230.0 million in debt outstanding and approximately $0.03 million of outstanding letters of credit under our senior secured credit facility and $550.0 million in 2019 senior notes, excluding the premium of $2.0 million received on the October 2011 offering of the 2019 senior notes. Additionally, we had approximately $482.5 million available for borrowings under our senior secured credit facility at March 31, 2012. We believe such availability as well as cash flows from operations, cash on hand and the issuance of the old notes in April 2012, provide us with the ability to implement our planned exploration and development activities.

As of June 28, 2012, we had no outstanding debt under our senior secured credit facility and approximately $785.0 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 three months ended March 31, 2012 and 2011 and the years ended December 31, 2011, 2010 and 2009 are as follows:

| (in thousands) | Three months ended March 31, 2012 | Three months ended March 31, 2011 | Years ended December 31, 2011 | Years ended December 31, 2010 | Years ended December 31, 2009 |
|---|---|---|---|---|---|
| Net cash provided by operating activities | $ 91,402 | $ 75,988 | $ 344,076 | $ 157,043 | $ 112,669 |
| Net cash used in investing activities | (252,192) | (192,360) | (706,787) | (460,547) | (361,333) |
| Net cash provided by financing activities | 145,000 | 100,890 | 359,478 | 319,752 | 250,139 |
| Net increase (decrease) in cash | $ (15,790) | $ (15,482) | $ (3,233) | $ 16,248 | $ 1,475 |

Table of Contents

***Cash flows provided by operating activities***

Net cash provided by operating activities was $91.4 million and $76.0 million for the three months ended March 31, 2012 and 2011, respectively. The increase of $15.4 million was largely due to significant increases in revenue due to increased production, as well as an increase in the market price for oil.

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 $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 had cash flows used in investing activities of approximately $252.2 million and $192.4 million for the three months ended March 31, 2012 and 2011, respectively, which is an increase of $59.8 million. A significant portion of our capital expenditures for the three months ended March 31, 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 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 had cash flows used 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 three months ended March 31, 2012 and 2011 and the years ended December 31, 2011, 2010 and 2009 is summarized in the table below.

| | Three months ended March 31, | | Years ended December 31, | | |
|---|---|---|---|---|---|
| **(in thousands)** | **2012** | **2011** | **2011** | **2010** | **2009** |
| Restricted cash | $ | $ | $ | $ | $ 2,201 |
| Capital expenditures: | | | | | |
| Oil and gas properties | (247,280) | (187,576) | (687,062) | (454,161) | (340,636) |
| Pipeline and gathering assets | (3,859) | (3,424) | (13,368) | (4,277) | (19,995) |
| Other fixed assets | (1,053) | (1,374) | (6,413) | (2,198) | (3,071) |
| Proceeds from other asset disposals | | 14 | 56 | 89 | 168 |
| Net cash used in investing activities | $ (252,192) | $ (192,360) | $ (706,787) | $ (460,547) | $ (361,333) |

Table of Contents

***Capital expenditure budget***

In June 2012, our board of directors approved a revised budget of $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.

The amount, timing and allocation of capital expenditures are largely discretionary and within management's control. If oil and 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 $145.0 million and $100.9 million for the three months ended March 31, 2012 and 2011, respectively.

Net cash provided by financing activities for the three months ended March 31, 2012 was the result of borrowings on our senior secured credit facility.

Net cash provided by financing activities for the three months ended March 31, 2011 was largely the result of our first issuance of 2019 senior notes in an aggregate principal amount of $350.0 million in January 2011 as well as borrowings on the former Broad Oak credit facility totaling $38.6 million and payments on our senior secured credit facility of $177.5 million and term loan of $100.0 million. Additionally, we incurred $10.2 million in loan costs for the three months ended March 31, 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 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.

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.

Table of Contents

***Debt***

At March 31, 2012, we were a party only to our senior secured credit facility and the indenture governing the 2019 senior 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 notes.

*Senior secured credit facility.* Laredo Petroleum, Inc. is the borrower under our senior secured credit facility, which had a capacity of $1.0 billion, a borrowing base of $712.5 million and approximately $230.0 million outstanding and $482.5 million available for borrowing at March 31, 2012. 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 March 31, 2012, we had one letter of credit outstanding totaling approximately $0.03 million under our senior secured credit facility. 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 March 31, 2012, the applicable margin rates were 1.00% for the adjusted base rate advances and 2.00% for the Eurodollar advances. The amount of the senior secured credit facility outstanding at March 31, 2012 was subject to an interest rate of approximately 2.25%. 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 stock of Laredo Petroleum, Inc.), including oil and natural gas properties constituting at least 80% of the present value of our proved reserves owned now or in the future. At March 31, 2012, we were subject to the following financial and non-financial ratios on a consolidated basis:

- a current ratio at the end of each fiscal quarter, as defined by the agreement, that is not permitted to be less than 1.00 to 1.00; and

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

Our senior secured credit facility contains both financial and non-financial covenants. We were in compliance with these covenants at March 31, 2012, 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;

- 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;

Table of Contents

- 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 March 31, 2012, we were in compliance with the terms of our senior secured credit facility. If an event of default exists under our senior secured credit facility, the lenders will be able to accelerate the maturity of our senior secured credit facility and exercise other rights and remedies. As of March 31, 2012, each of the following will be an event of default:

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

failure to cure any borrowing base deficiency in accordance with the senior secured credit facility;

a change of control, as defined in our senior secured credit facility; and

notification if an "event of default" shall occur under the indenture governing our senior unsecured notes.

Table of Contents

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 March 31, 2012, we had one letter of credit outstanding totaling approximately $0.03 million under our senior secured credit facility.

We subsequently entered into the third amendment to our senior secured credit facility on April 24, 2012, which allowed for the issuance of additional senior unsecured notes in the aggregate amount of $500.0 million. Additionally, on April 27, 2012, we entered into the fourth amendment to our senior secured credit facility, which increased the facility capacity to $2.0 billion and the borrowing base to $785 million. Refer to Note N of our unaudited consolidated financial statements included elsewhere in this prospectus for further discussion of these amendments.

Subsequent to March 31, 2012, we borrowed an additional $50.0 million under our senior secured credit facility on April 5, 2012. As of June 28, 2012, the outstanding balance under our senior secured credit facility was zero as all outstanding amounts were paid with the proceeds of our issuance of the old notes in April 2012 as discussed below.

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 under the facilities bore interest payable quarterly at an Adjusted Base Rate or Adjusted LIBOR plus an applicable margin based on the ratio of outstanding revolving credit to the conforming borrowing base. At June 30, 2011, the applicable margin rates were 1.50% for the Adjusted Base Rate advances and 2.50% for the Eurodollar advances. Additionally, Broad Oak was also required to pay a quarterly commitment fee of 0.5% on the unused portion of the bank's commitment.

The Broad Oak credit facility was secured by a first priority lien on Broad Oak's oil and 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.

As of December 31, 2010 and 2009, borrowings outstanding under 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 principal amount and $200 million principal amount, respectively, of $9^1/_2$% senior notes due 2019. The 2019 senior 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 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 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 indenture governing the 2019 senior notes 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 notes may be accelerated in certain circumstances upon an event of default as set forth in the indenture governing the 2019 senior notes.

Table of Contents

Laredo Petroleum, Inc. may redeem all or a portion of the 2019 senior notes at any time on or after February 15, 2015, on not less than 30 or more than 60 days' prior notice in amounts of $2,000 or whole multiples of $1,000 in excess thereof, at the redemption prices (expressed as percentages of principal amount) of 104.750% for the twelve-month period beginning on February 15, 2015, 102.375% for the twelve-month period beginning on February 15, 2016 and 100.000% for the twelve-month period beginning on February 15, 2017 and at any time thereafter, together with accrued and unpaid interest, if any, thereon to the applicable date of redemption (subject to the rights of holders of record on relevant record dates to receive interest due on an interest payment date). In addition, before February 15, 2015, Laredo Petroleum, Inc. may redeem all or any part of the 2019 senior notes at a redemption price equal to the sum of the principal amount thereof, plus a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the applicable redemption date (subject to the rights of holders of record on relevant record dates to receive interest due on an interest payment date). Furthermore, before February 15, 2014, Laredo Petroleum, Inc. may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the 2019 senior notes (including the principal amount of any additional notes) with the net proceeds of a public or private equity offering at a redemption price of 109.500% of the principal amount of the 2019 senior notes, plus accrued and unpaid interest, if any, to the date of redemption (subject to the rights of holders of record on relevant record dates to receive interest due on an interest payment date), if at least 65% of the aggregate principal amount of the 2019 senior notes (including the principal amount of any additional notes) issued under the indenture governing the 2019 senior notes remains outstanding immediately after such redemption and the redemption occurs no later than 180 days of the closing date of such equity offering. Laredo Petroleum, Inc. may also be required to make an offer to purchase the 2019 senior notes upon a change of control triggering event.

In connection with the issuance of the 2019 senior notes, Laredo Petroleum, Inc. and the guarantors party thereto entered into registration rights agreements with the initial purchasers of the 2019 senior notes and agreed to file with the SEC a registration statement with respect to an offer to exchange the 2019 senior 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 notes for substantially identical notes registered under the Securities Act was consummated on January 13, 2012.

Refer to Note C of our audited consolidated financial statements included elsewhere in this prospectus for further discussion of the 2019 senior notes.

Subsequent to March 31, 2012, and as described in this prospectus, Laredo Petroleum, Inc. completed an offering of $500 million aggregate principal amount of old notes. The old 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 old notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Petroleum Holdings, Inc. and the guarantors. The net proceeds from the old notes were used (i) to pay in full $280.0 million outstanding under our senior secured credit facility, and (ii) for general working capital purposes. As of June 28, 2012, we had a total of $1.05 billion of senior unsecured notes outstanding.

Table of Contents

**Obligations and Commitments**

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

| | 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 March 31, 2012, we had approximately $145.0 million outstanding on our senior secured credit facility due in 2016; however this balance was subsequently paid-in-full in April 2012 with the proceeds of the old 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 March 31, 2012, our drilling rig commitments total approximately $27.2 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 March 31, 2012, our deferred premiums total approximately $25.5 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 March 31, 2012, our asset retirement obligation totals approximately $14.2 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 March 31, 2012, our contractual obligations included an addition of approximately $5.5 million for the estimated total liability payable for our performance unit awards as of March 31, 2012, which will be payable in December 2014.

**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.

Table of Contents

***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 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.

***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 "Other 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.

***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

Table of Contents

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 March 31, 2012, December 31, 2011, 2010 and 2009, we had deferred tax assets of $80.8 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 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 three 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 March 31, 2012 and December 31, 2011, (ii) the net basis differences in our oil and gas properties represented by a net deferred tax liability at March 31, 2012 and December 31, 2011, and (iii) our full cost ceiling cushion at March 31, 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 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.

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 U.S. has been relatively low in recent years and did not have a material impact on our results of operations for the period from December 31, 2009 through the three months ended March 31, 2012. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and we do experience inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which we operate.

Table of Contents

**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 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 March 31, 2012, the weighted average indebtedness outstanding on our senior secured credit facility bore an annual weighted average interest rate of 2.19%. Based on the total outstanding borrowings under this facility at March 31, 2012 of $230.0 million, a 1.0% increase in each of the average LIBOR rates and federal funds rates would result in increased annual interest expense of $2.3 million before giving effect to interest rate derivatives.

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 March 31, 2012, we had interest rate swaps and one interest rate cap outstanding for a notional amount of $260.0 million with fixed pay rates ranging from 1.11% to 3.41% and terms expiring from June 2012 to September 2013.

*Counterparty and customer credit risk.* Our principal exposures to credit risk are through receivables resulting from derivatives contracts (approximately $23.3 million at March 31, 2012), joint interest receivables (approximately $35.3 million at March 31, 2012) and the receivables from the sale of our oil and natural gas production (approximately $53.1 million at March 31, 2012), which we market to energy marketing companies and refineries.

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. At March 31, 2012, we had two customers that made up approximately 35% and 11% of our total oil and gas sales accounts receivable. At December 31, 2011, we had four customers that made up approximately 32%, 16%, 14% and 11% of our total oil and gas sales accounts receivable. At December 31, 2010, we had three customers that made up approximately 41%, 16% and 14% of our total oil and gas sales accounts receivable.

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. At March 31, 2012, we had three customers that made up approximately 24%, 22% and 21% of our total joint operations receivables. At December 31, 2011, we had three customers that made up approximately 30%, 17% and 16% of our total joint operations receivables. At December 31, 2010, we had two customers that made up approximately 77% and 11% of our total joint operations receivables. Refer to Note I of our audited consolidated financial statements included elsewhere in this prospectus for additional disclosures regarding credit risk.

Table of Contents

## BUSINESS

### Overview

We are an independent energy company focused on the exploration, development and acquisition of oil and natural gas in the Permian and Mid-Continent regions of the United States. Our activities are primarily focused in the Wolfberry and deeper horizons of the Permian Basin in West Texas and the Anadarko Granite Wash in the Texas Panhandle and Western Oklahoma, where we have assembled 174,608 net acres and 37,320 net acres, respectively, as of March 31, 2012. The oil and liquids-rich Permian Basin and the liquids-rich Anadarko Granite Wash are characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and significant initial production rates.

Based upon drilling results from over 750 of our gross vertical wells, we believe our vertical program in these areas has been largely de-risked. Our vertical development drilling activity is complemented by a rapidly emerging horizontal drilling program, which may add significant production and reserves in multiple producing horizons on the same acreage. These drilling programs comprise an extensive, multi-year inventory of exploratory and development opportunities. As of May 31, 2012, we have drilled 42 gross horizontal wells in the Permian and 18 gross horizontal wells in the Anadarko Granite Wash.

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 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. In 1991, Mr. Foutch formed Colt Resources Corporation ("Colt"), with an institutional sponsor. Colt was sold in a private transaction in 1996 for approximately $33 million. In 1997, Mr. Foutch formed Lariat Petroleum, Inc. ("Lariat") with a large institutional sponsor investing approximately $74 million and using approximately $100 million of debt. In 2001, Lariat subsequently was sold for approximately $333 million. Most recently, in 2002, Mr. Foutch and several of our current managers formed Latigo Petroleum, Inc. ("Latigo"), with institutional sponsors investing approximately $160 million, and utilizing an additional approximately $200 million of debt. Latigo was sold in 2006 for approximately $750 million. All of these companies executed the same fundamental business strategy in the same general operating areas that created significant growth in cash flow, production and reserves.

Since our inception, we have rapidly grown our cash flow, production and reserves through our drilling program. We also seek acquisition opportunities that are complementary to our assets and provide upside potential that is competitive with our existing property portfolio. On July 1, 2011, we completed the acquisition of Broad Oak for a combination of equity and cash. This acquisition provided us incremental scale and significant additional exposure to attractive vertical and horizontal oil and liquids-rich natural gas drilling opportunities. The acquired properties are concentrated on a contiguous land position located in the Permian Basin, primarily in Reagan County, and are being drilled targeting Wolfberry production. This acreage, totaling approximately 64,000 net acres, approximately doubled our Permian Basin position and is immediately south of and on trend with our legacy Permian Basin properties in Glasscock and Howard Counties. We believe the success Laredo has achieved to date in drilling our vertical and horizontal wells may add significant value to this newly acquired acreage. In December 2011, we completed a Corporate Reorganization and IPO. See "  Corporate History and Structure."

Our net cash provided by operating activities was approximately $91.4 million for the three months ended March 31, 2012. Our net average daily production for the same period was approximately 27,995 BOE/D, and our net proved reserves were an estimated 156,453 MBOE as of December 31, 2011.

Table of Contents

The following table summarizes net acreage and producing wells as of March 31, 2012, total estimated net proved reserves as of December 31, 2011, and average daily production for the three months ended March 31, 2012 in our principal operating regions. Our reserve estimates as of December 31, 2011 are based on a report prepared by Ryder Scott, our independent reserve engineers. Based on such report, 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 | | | | | Three months ending March 31, 2012 average daily production(6) | At March 31, 2012 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Estimated net proved reserves(1)(2) | | | Identified potential drilling locations(4) | | | | Producing wells | |
| | MBOE(3) | % of Total reserves | % Oil | Total | PUD locations(5) | (BOE/D) | Net acreage | Gross | Net |
| Permian | 101,441 | 65% | 52% | 5,669 | 872 | 18,283 | 174,608 | 682 | 646 |
| Anadarko Granite Wash | 45,101 | 29% | 8% | 335 | 207 | 7,286 | 37,320 | 179 | 134 |
| Other(7) | 9,911 | 6% | 3% | | | 2,426 | 166,492 | 351 | 177 |
| Total | 156,453 | 100% | 36% | 6,004 | 1,079 | 27,995 | 378,420 | 1,212 | 957 |

(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) Our reserves are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. The 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 in the Permian area were $7.48/Mcf 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 (30,966 net acres) and Central Texas Panhandle (44,636 net acres), as well as the Dalhart Basin, which is a new exploration effort (90,890 net acres) targeting liquids-rich formations that are less than 7,000 feet in depth.

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 acreage positions and

Table of Contents

successful exploratory drilling. We plan to continue our conventional vertical drilling programs, especially in the Permian Basin, and to further de-risk our rapidly emerging horizontal plays in both the Permian and Anadarko Basins. As of May 31, 2012, we have a total of 15 operated drilling rigs running. Twelve of these rigs are working on our properties in the Permian Basin, eight of which are drilling vertical wells and four are drilling horizontal wells. Three rigs are operating on our properties in the Anadarko Granite Wash, all of which are drilling horizontal wells.

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. Each of these factors must be addressed in order to reduce the risk and uncertainty associated with (or "de-risk") our exploration and production program:

- Does the prospective reservoir underlie our acreage position and can it be defined both vertically and horizontally?

- Are the petro-physics 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 over 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 petro-physics 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") in order to minimize costs and maximize recoveries.

As of December 31, 2011, we had identified a total of 6,004 gross potential drilling locations, 5,669 of which underlie our Permian Basin acreage and 335 of which are located in our Anadarko Basin focus area. Both areas have a vertical and horizontal drilling component relative to the types of potential drilling locations. While the Permian and Anadarko areas share some of the same qualifying technical metrics that define a potential location, as a matter of clarification, we consider the Granite Wash area to represent a conventional drilling program, while the potential locations identified in the Permian are characterized as a resource play.

In the Anadarko Basin, both the Granite Wash horizontal and vertical 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, petrophysical data describing the reservoir rock as derived from cores and, where appropriate, 3D seismic data provide the technical basis from which we identified the potential locations.

In the Permian Basin, both the Wolfberry interval (comprised of multiple producing formations) and the individual targeted shale formations are considered a resource play. As such, the mapping of the gross interval for each of the producing formations underlying a majority of our entire acreage position is the main factor we considered in identifying our potential locations. In the general region and immediately around our acreage position, publicly available well data exists from a significant

Table of Contents

number of vertical wells (in excess of several thousand for the Cline Shale alone) that have allowed us to define the areal extent of each of the producing intervals, whether the whole vertical Wolfberry section or the targeted Cline and Wolfcamp Shales. In addition to this publicly available well data, we have also incorporated our internally generated information from cores, 3D seismic, open hole logging and reservoir engineering data into defining the extent of the targeted intervals, the ability of such intervals to produce commercial quantities of hydrocarbons, and the viability of the potential locations. As with the Granite Wash drilling program, the timing of drilling the identified potential Permian locations will be influenced by several factors, including commodity prices, capital requirements, Texas Railroad Commission ("RRC") well-spacing requirements and a continuation of the positive results from both our the vertical and horizontal development drilling program.

**Our Business Strategy**

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

***Grow production and reserves through our lower-risk vertical drilling.*** We leverage our operating and technical expertise to establish large, contiguous acreage positions. We believe that we have reduced the risk and uncertainty associated with (or "de-risked") our core acreage positions by our vertical development activity, and we intend to generate significant growth in cash flows, production and reserves by drilling our inventory of locations. Our vertical development drilling program provides repeatable, predictable, low-risk production growth but also serves as an efficient way to obtain additional critical sub-surface data to target potential horizontal wells.

***Increase recovery and capital efficiency through our horizontal drilling.*** Our horizontal drilling program is designed to further capture the upside potential that may exist on our properties. Horizontal drilling may significantly increase our well performance and recoveries compared to our vertical wells. In addition, horizontal drilling may be economic in areas where vertical drilling is currently not economical or logistically viable. We believe multiple vertically stacked producing horizons may be developed using horizontal drilling techniques in both our Permian and Anadarko Granite Wash plays.

***Apply our technical expertise to reduce risk in our current asset portfolio, optimize our development program and evaluate emerging opportunities.*** Our management team has significant experience in successfully identifying opportunities to enhance our cash flow, production and reserves in the basins in which we operate. Our practice is to make a substantial upfront investment 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 seek to economically de-risk our opportunities to the extent possible before committing to a drilling program.

***Enhance returns through prudent capital allocation 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. 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 in our joint ventures, having drilled 24 wells in the ExxonMobil joint venture and 129 wells under the Linn Energy joint venture as of December 31, 2011.

***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

Table of Contents

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 conservative 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:

***Management team with extensive operating experience in core areas of operation.*** Our management team has extensive industry experience and a proven record of providing a significant return on investment. Four of our other seven senior officers have worked with Mr. Foutch at one or more of his previous companies. This has resulted in a high degree of continuity among members of our executive management and has enabled us to attract and retain key employees from previous companies as well as other successful exploration and production companies. 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 over twenty years of experience and knowledge directly associated with our current primary operating areas. As of May 31, 2012 approximately 56% of our full-time employees are experienced technical employees, including 25 petroleum engineers, 18 geoscientists, 20 landmen and 52 technical support staff.

***Economic, multi-year drilling inventory.*** We have assembled a portfolio of approximately 6,000 gross identified potential drilling locations as of December 31, 2011. We believe our focus on data-rich, mature producing basins with well studied geology, engineering practices and concentrated operation, combined with new technologies in the Permian and Anadarko Basins, as well as our disciplined assessment and monitoring of the three factors that we believe help to de-risk our drilling and exploration projects, as described above, significantly decreases the risk profile of our identified drilling locations. As of May 31, 2012, we have approximately 1,908 square miles of 3D seismic data supporting our exploratory and development drilling programs. From our formation in 2006 through May 31, 2012, we have drilled over 900 gross vertical and horizontal wells with a success rate of approximately 99%. Our drilling activity has been and will continue to be focused on liquids-rich opportunities in the Permian Basin and Anadarko Granite Wash, where we see liquids-rich natural gas that ranges from 1,225 to 1,460 Btu per cubic foot and 1,115 to 1,230 Btu per cubic foot, respectively. Pursuant to our existing percentage of proceeds contracts during December 2011, our natural gas liquids yield was 130 Bbls/MMcf in the Permian Basin and 69 Bbls/MMcf in the Anadarko Granite Wash and our ratio of residue natural gas to wellhead natural gas was 69% and 84%, respectively.

***Significant operational control.*** We operate wells that represent approximately 97% of the value of our proved developed oil and natural gas 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 operation control over most of our identified potential drilling locations.

***Our gathering infrastructure provides secure and timely takeaway capacity and enhanced economics.*** Our wholly-owned subsidiary, Laredo Gas Services, LLC, has invested approximately $60 million in over 230 miles of pipeline in our natural gas gathering systems in the Permian and Anadarko Basins as of March 31, 2012. We have also installed over 420 miles of natural gas gathering lines to 63 central delivery points on our Permian acreage in Reagan County. 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, they provide us with multiple sales outlets through interconnecting pipelines, minimizing the risks of shut-ins awaiting pipeline connection or curtailment by downstream pipelines.

***Financial strength and flexibility.*** We maintain a conservative financial profile in order to preserve operational flexibility and financial stability. At March 31, 2012, on a pro forma basis, after giving effect to the offering of old notes and the application of the net proceeds described herein, we would have had approximately $785 million available for borrowings under the issuer's senior secured credit facility (giving effect to the increase in the borrowing base) and total debt of approximately $1.05 billion, which is 2.3 times our annualized Adjusted EBITDA for the first three months of 2012. We have diversified our capital sources, including raising $319.4 million through the IPO in December 2011, raising $550 million aggregate principal amount by issuing the 2019 senior notes in January and October 2011 and raising $500 million aggregate principal amount by issuing the old notes in April 2012. We believe that our operating cash flow and the aforementioned liquidity sources provide us with the ability to implement our planned exploration and development activities.

***Strong institutional investor support and corporate governance.*** Warburg Pincus is our institutional investor and has many years of relevant experience in financing and supporting exploration and production companies and management teams, having been the lead investor in several such companies. Warburg Pincus has been an institutional investor in two previous companies operated by members of our management team. To date, Warburg Pincus, certain members of our management and our independent directors have together invested a total of $1.2 billion (including through investments in Broad Oak). Warburg Pincus did not sell shares in the IPO and retains a significant interest in Laredo. We believe that our board of directors is exceptionally qualified and represents a significant resource. It is comprised of Laredo management, representatives of Warburg Pincus and independent individuals with extensive industry and business expertise. We actively engage our board of directors on a regular basis for their expertise on strategic, financial, governance and risk management activities.

## Focus Areas

We focus on developing a balanced inventory of quality drilling opportunities that provide us with the operational flexibility to economically develop and produce oil and natural gas reserves from conventional and unconventional formations. Our properties are currently located in the prolific Permian and Mid-Continent regions of the United States, where we leverage our experience and knowledge to identify and exploit additional upside potential. We have been successful in delivering repeatable results through internally generated vertical and horizontal drilling programs.

### *Permian Basin*

The Permian Basin, located in west Texas and southeastern New Mexico, is one of the most prolific onshore oil and natural gas producing regions in the United States. It is characterized by an extensive production history, mature infrastructure, long reserve life and hydrocarbon potential in multiple intervals. Our Permian activities are centered on the eastern side of the basin approximately

Table of Contents

35 miles east of Midland, Texas in Glasscock, Howard, Reagan and Sterling Counties. As of March 31, 2012, we held 174,608 net acres in over 490 sections with an average working interest of 95% in wells drilled to date.

The overall Wolfberry interval, the principal focus of our drilling activities, is an oil play that also includes a liquids-rich natural gas component. Our production/exploration fairway extends approximately 20 miles wide and 80 miles long. While exploration and drilling efforts in the southern half of our acreage block have been centered on the shallower portion of the Wolfberry (Spraberry, Dean and Wolfcamp formations) the emphasis in the northern half has been on the deeper intervals, including the Wolfcamp, Cline Shale, Strawn and Atoka formations. Considering the geology and the reservoir extent of each contributing formation, we now have identified significant potential throughout our total acreage block for the entire Wolfberry interval from the shallow zones to the deepest.

As of May 31, 2012 we have drilled and completed approximately 650 gross vertical wells and have defined the productive limits on our acreage throughout the trend. The success of our vertical drilling program, coupled with industry activity, has substantially reduced risks associated with our future drilling programs in the Wolfberry interval.

We have expanded our drilling program to include a horizontal component targeting the Cline and Wolfcamp Shales. The drilling of the Cline Shale, located in the lower Wolfberry, was initiated after our extensive technical review that included coring and testing the Cline separately in multiple vertical wells. We believe the Cline Shale exhibits similar petrophysical attributes and favorable economics compared to other liquids-rich shale plays operated by other companies, such as in the Eagle Ford and Bakken Shale formations. We have acquired 3D seismic data to assist in fracture analysis and the definition of the structural component within the Cline Shale.

We have drilled 12 gross horizontal Wolfcamp Shale wells as of May 31, 2012 with encouraging results out of the uppermost interval (the Wolfcamp "A"). The Middle and Lower Wolfcamp Shale intervals also look prospective based on open hole logs and petrophysical data we have gathered through coring. This data, along with industry activity to the south, suggests that multiple, repeatable shale opportunities underlay a majority of our acreage position. As of May 31, 2012, we have drilled a total of 42 gross horizontal wells in the Wolfcamp and Cline formations, of which 30 are in the Cline Shale and 12 in the Wolfcamp Shale.

We have over 5,600 total gross identified potential drilling locations (both vertical and horizontal) in the Permian, all of which are within the larger Wolfberry interval.

***Anadarko Granite Wash***

Straddling the Texas/Oklahoma state line, our Granite Wash play extends over a large area in the western part of the Anadarko Basin. As of March 31, 2012, we held 37,320 net acres in Hemphill County, Texas and Roger Mills County, Oklahoma. Our play consists of vertical and horizontal drilling opportunities targeting the liquids-rich Granite Wash formation. By utilizing the whole core data we obtained early in the exploration process and the subsurface information from our vertical wells, enhanced logging techniques and other wells drilled by the industry, we have developed a detailed regional geologic depositional and engineering understanding. As a result, we have been able to target our current vertical development drilling program in the higher productive areas. As of December 31, 2011, we have drilled and completed approximately 150 gross vertical wells.

Table of Contents

Our horizontal Granite Wash program is in the evaluation phase with our current emphasis on reducing risks through our drilling program and by incorporating practices similar to the industry's successful drilling results in the immediate area. The economic viability of our Anadarko Granite Wash horizontal program has been validated by our recent completions and by the announced success of our competitors in close proximity to our acreage. In addition to the Granite Wash zones tested to date, we believe that additional potential upside exists within the multiple mapped and targeted horizontal Granite Wash zones that remain to be tested. As a result of our and the industry's recent horizontal success, we anticipate the majority of our Granite Wash drilling going forward to be horizontal. As of December 31, 2011, we have approximately 100 gross identified potential drilling locations for the horizontal Granite Wash, which includes both our Texas and Oklahoma acreage.

In addition to the Granite Wash intervals in this area, there are both shallower and deeper zones that we believe are prospective, including the Cleveland and Morrow channel sands. We have acquired 3D seismic data to help further define the areal extent of these additional formations. Considering the Granite Wash and Upper Morrow intervals identified as of December 31, 2011, we estimate there are approximately 335 gross identified potential vertical and horizontal drilling locations, all of which are in the Granite Wash.

**Other Areas**

In addition to our Permian and Anadarko Granite Wash plays, we continue to evaluate opportunities in three other areas within our core operating regions.

The Dalhart Basin is located on the western side of the Texas Panhandle. As of March 31, 2012, we held 90,890 net acres in the Dalhart Basin. It is characterized by both a conventional Granite Wash play and several potential liquids-rich shale plays that may underlie a significant portion of the entire area. Both targeted intervals are considered oil plays at depths of less than 7,000 feet. Our initial 3D seismic program of approximately 155 square miles was recently completed and is in the final stages of being interpreted. As of May 31, 2012, we have drilled three gross vertical wells in the Dalhart Basin.

The second area is centrally located in the Central Texas Panhandle, where our operations are currently conducted through our joint venture with ExxonMobil. As of March 31, 2012, we held 44,636 net acres in the Central Texas Panhandle. The prospective zones in this area are relatively shallow (less than 9,500 feet), with a majority being predominately natural gas.

The third area is located in the eastern end of the Anadarko Basin, in Caddo County, Oklahoma. As of March 31, 2012, we held 30,966 net acres in the Eastern Anadarko. There are multiple targets to drill in this area, varying in depth between 8,000 feet and 22,000 feet, which are predominantly dry natural gas. While our economic metrics require higher natural gas prices to justify additional drilling, the area could play a meaningful role in our future if natural gas prices increase.

These latter two areas, which represent 12% of our production and 6% of our estimated proved reserves as of December 31, 2011, may become more compelling in the future if natural gas prices increase.

**Our Operations**

***Estimated proved reserves***

Unless otherwise specifically identified in this prospectus, the information with respect to our estimated proved reserves presented below has been prepared by Ryder Scott, our independent reserve engineers, in accordance with the rules and regulations of the SEC applicable to the periods presented. Our net proved reserves are estimated at 156,453 MBOE as of December 31, 2011, 40% of which were classified as proved developed and 36% oil. The following table presents summary data for each of our core operating areas as of December 31, 2011. Our estimated proved reserves at December 31, 2011

Table of Contents

assume our ability to fund the capital costs necessary for their development and are impacted by pricing assumptions. In addition, we may not be able to raise the amounts of capital that would be necessary to drill a substantial portion of our proved undeveloped reserves. See "Risk Factors Risks related to our business Estimating reserves and future net revenues involves uncertainties. Decreases in oil and natural gas prices, or negative revisions to reserve estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil and natural gas assets" in the 2011 Annual Report incorporated by reference into this prospectus.

| | **At December 31, 2011 Proved Reserves (MBOE)(1)** | **% of Total** |
|---|---|---|
| Area: | | |
| Permian Basin | 101,441 | 65% |
| Anadarko Granite Wash | 45,101 | 29% |
| Other(2) | 9,911 | 6% |
| Total | 156,453 | 100% |

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

(2) Includes Eastern Anadarko, Central Texas Panhandle and Dalhart Basin.

The following table sets forth more information regarding our estimated proved reserves at December 31, 2011 and 2010. Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserves at December 31, 2010 and December 31, 2011. The reserve estimates at December 31, 2011 and 2010 were prepared in accordance with the SEC's rules regarding oil and natural gas reserve reporting currently in effect. The information in the following table does not give any effect to our commodity hedges.

| | **At December 31,** | |
|---|---|---|
| | **2011** | **2010** |
| Estimated proved reserves: | | |
| Oil and condensate (MBbl) | 56,267 | 44,847 |
| Natural gas (MMCF) | 601,117 | 550,278 |
| Total estimated proved reserves (MBOE)(1) | 156,453 | 136,560 |
| Proved developed producing (MBOE)(1) | 59,631 | 39,300 |
| Proved developed non-producing (MBOE)(1) | 3,564 | 5,533 |
| Proved undeveloped (MBOE)(1) | 93,258 | 91,727 |
| Percent developed | 40% | 33% |

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

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

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

*Qualifications of technical persons and internal controls over reserves estimation process.* In accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and guidelines established by the SEC, Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2011 and 2010 included in this prospectus. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

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

John E. Minton, our Senior Vice President of Reservoir Engineering, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. He has over 38 years of practical experience with approximately 34 years of this experience being in the estimation and evaluation of reserves. He has been a registered Professional Engineer in the State of Oklahoma since 1982. He has a Bachelor of Science degree in Mechanical Engineering and is a life member in good standing of the Society of Petroleum Engineers. Mr. Minton reports directly to our President and Chief Operating Officer. Reserve estimates are reviewed and approved by senior engineering staff with final approval by our President and Chief Operating Officer and certain other members of our senior management. Our senior management also reviews our independent engineers' reserve estimates and related reports with senior reservoir engineering staff and other members of our technical staff.

***Proved undeveloped reserves***

Our proved undeveloped reserves increased from 91,727 MBOE at December 31, 2010 to 93,258 MBOE at December 31, 2011. 22,844 MBOE of proved undeveloped reserves were added during the year, (i) 15,009 MBOE of which were added from 155 wells in the Permian Basin that were previously unproved locations, but were proved up by drilling offset locations during the year and (ii) 7,835 MBOE of which were added from 47 wells in the Anadarko Granite Wash that became economic based on updated mapping of expected reserves. During 2011, 10,704 MBOE of proved undeveloped reserves were converted to proved developed reserves as a result of drilling 147 locations

Table of Contents

at a total net cost of approximately $259 million. 142 of these locations were in the Permian Basin and five were in the Anadarko Basin. Negative revisions of 10,609 MBOE of proved undeveloped reserves during 2011 were primarily the result of removing potential Permian Basin and Anadarko Basin locations. Our anticipated capital costs for directionally drilling or obtaining additional surface locations increased for 33 vertical wells in our Anadarko Granite Wash play, making these locations uneconomic to drill at current gas prices. We also decided to drill 149 Permian Basin locations (with proved reserves through the upper Wolfcamp zone) deeper into the non-proved lower Wolfcamp through Atoka zones. The additional capital costs to drill these wells deeper, based on the shallow proved reserves only, made these locations uneconomic as proved locations. During 2011, we drilled 19 wells to test the deeper, unproved horizons, and such testing indicates these zones, combined with the shallower uphole zones, could result in economic completions.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2011 reserve report are $1.9 billion. Based on this report, the capital estimated to be spent in 2012, 2013, 2014, 2015 and 2016 to develop the proved undeveloped reserves is $202 million, $395 million, $529 million, $702 million and $35 million, respectively. All of the proved undeveloped locations are expected to be drilled within a five year period.

***Production, revenues and price history***

The following table sets forth information regarding production, revenues and realized prices and production costs for the three months ended March 31, 2012 and 2011 and for the years ended December 31, 2011, 2010 and 2009. Our reserves and production are reported in two streams: crude oil and liquids-rich natural gas. The economic value of the natural gas liquids in our liquids-rich natural gas is included in the wellhead natural gas price. For additional information on price calculations, see information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Table of Contents

| | For the three months ended March 31, | | For the years ended December 31, | | |
|---|---|---|---|---|---|
| | **2012** | **2011** | **2011** | **2010** | **2009** |
| Production data: | | | | | |
| Oil (MBbls) | 1,067 | | | | |