LAREDO
PETROLEUM

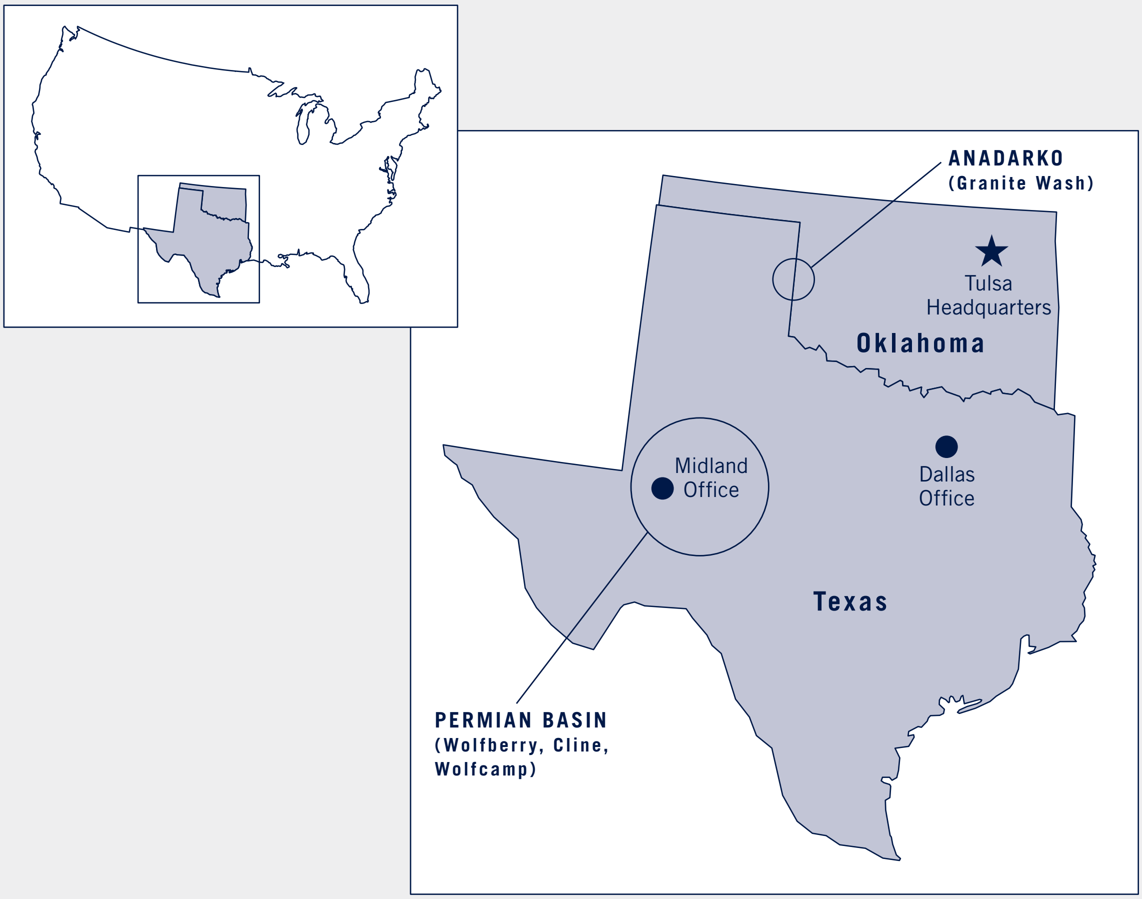
Laredo Petroleum | 2011 annual report

Corporate Profile

Laredo Petroleum is an independent energy company with headquarters in Tulsa, Oklahoma. Laredo's business strategy is focused on the exploration, development and acquisition of oil and natural gas properties in the Permian and Mid-Continent regions of the United States.

Areas of Operation

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. These plays are characterized by high oil and liquids-rich natural gas content, multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and significant initial production rates.




Financial Highlights

For the years ending December 31,	2011	2010	2009	2008
Total Production (Mboe)	8,654	5,212	3,563	1,546
Avg. Daily Production (Boe/D)	23,709	14,278	9,762	4,226
Proved Reserves (Mboe)	156,453	136,560	52,519	44,183
PDP Reserves (Mboe)	59,631	39,300	23,333	16,336
Revenue ($ in thousands)	510,270	242,000	96,574	74,187

Dear Stockholders:

Laredo is a growing company within an industry that is currently supplying more domestically-sourced hydrocarbons to U.S. consumers than in the 1970s. U.S. independent exploration and production companies are an important contributor to the American standard of living and economy, in terms of the available energy they find, the jobs they create and the value of the technology and energy they produce.

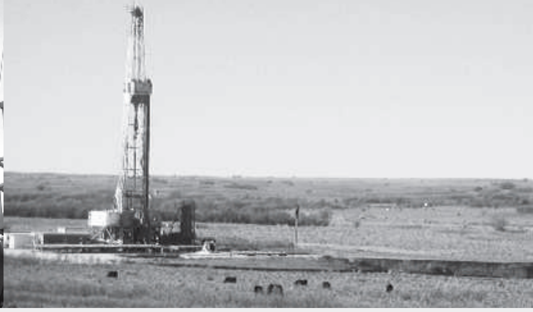
We are driving to deploy capital in a way that creates real value. We have sought to participate in the movement to expand America's independence from foreign energy sources, many of whom are not allies. We have been particularly focused on employing science and technology to limit risks and reveal the best exploration opportunities. Integrity has always been a big part of Laredo's business. Previously, as a private company, time was on our side, since our investors were willing and able to get their returns when the drill bit delivered them.

Being a public company amplifies Laredo's relevance to a host of new constituents. Our company is now a client of public shareholders, a participant in the capital markets, of interest to industry media, an information source for competitors and analysts in our plays, and to some, we might even be a faceless publicly traded stock.

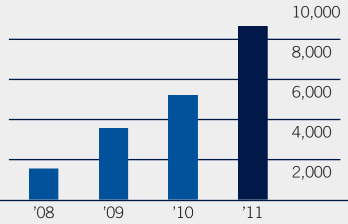
These competing constituents sometimes have goals and agendas that are not always aligned with Laredo's aim to create real value, perform our work and strengthen America's energy sector. I don't mean to say that these competing goals and agendas are wrong; they just aren't necessarily Laredo's. They might, for example, support a trader's goal to make the fastest returns through transacting in our stock, or someone possibly dismissing the importance of our domestic production.

Ultimately, we want the expectations of our company's constituents to track as closely as possible with the real decisions and outcomes of the company's board of directors, management and technical team. Do Laredo's conservative operational and financial risk practices correlate well to those which everyday investors in our stock perceive they are taking? How aligned are the fundamentals and long-term goals of our company with the stock performance, media reports, financial analyst views and so on? Are we making our case, through industry organizations, that our safe oil and gas exploration and drilling today will make an impact on America's long-term energy security?

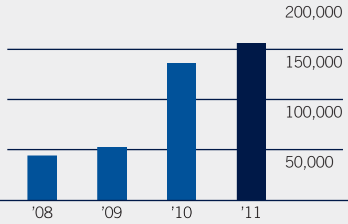
In the public markets, returns can be made on many sides of a trade. The success of the company isn't always the outcome a trader desires, especially when he may short our stock or buy options to sell. Volatility is often a more attractive quality to short-term investors. And increasingly, fund managers are evaluated on shorter time horizons for delivering returns than our normal industry exploration-to-production-to-revenue recognition cycle allows; the



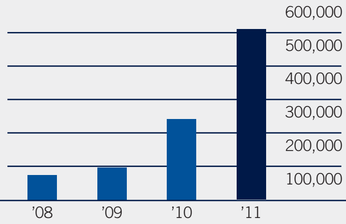
Total Production (Mboe)



Proved Reserves (Mboe)



Revenue ($ in thousands)



Randy A. Foutch
Chairman &
Chief Executive Officer

market has moved from annual return comparisons to monthly and sometimes even daily. The momentum and the faster trading required to produce these short-term returns are often accomplished through advanced algorithms and program orders. Does a black box really care about competency, integrity and the creation of value over the long term?

We rely on the media to bring forth the domestic energy message. The short-term nature of instant headlines, the demise of in-depth, debate-based reporting, as well as the rise of social media inhibit the complexities of energy issues from being fully discussed and understood in our culture. Democracy is dependent on education and the quest for truth. We will continue to be active in organizations like the Independent Petroleum Association of America and America's Natural Gas Alliance, to educate and promote the domestic energy message, within whatever context or backdrop we operate.

At Laredo, we stand firm. Our transition from a private to a public company has been a natural one, since our goals remain the same. We are focused on what we believe is a huge opportunity set, with significant potential value which we look to convert to realized value through the drill bit. Over time, we aim to bring forward future value to our shareholders through sound financial management (which includes prudently managing risk and raising and deploying capital) and by optimizing operational efficiencies. We know our work is important to the domestic energy picture and we will continue to explore and utilize the best technology available. In our clear agenda, we're happy to have your support.

Randy A. Foutch
Chairman & Chief Executive Officer

LAREDO PETROLEUM

Form 10-K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

or

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

Commission file number: 001-35380

Laredo Petroleum Holdings, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**45-3007926** (I.R.S. Employer Identification No.)
15 W. Sixth Street, Suite 1800 **Tulsa, Oklahoma** (Address of principal executive offices)	**74119** (Zip code)

(918) 513-4570

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

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

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☒

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The registrant was not a public company as of June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter, and therefore cannot calculate the aggregate market value of its common stock held by non-affiliates as of such date.

Number of shares of registrant's common stock outstanding as of March 19, 2012: 128,160,646

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2012 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2011, are incorporated by reference into Part III of this report for the year ended December 31, 2011.

Laredo Petroleum Holdings, Inc.
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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following terms are used throughout this Annual Report:

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

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

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

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

"*BOE*"—One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

"*BOE/D*"—BOE per day.

"*Btu*"—British thermal unit.

"*Completion*"—The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

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

"*Developed acreage*"—The number of acres that are allocated or assignable to productive wells or wells capable of production.

"*Development well*"—A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"*Dry hole*"—A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*Exploratory well*"—A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

"*Field*"—An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation*"—A layer of rock which has distinct characteristics that differs from nearby rock.

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

"*HBP*"—Held by production.

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

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

"*Identified potential drilling locations*"—Locations specifically identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves data on contiguous acreage and geologic formations. The availability of local infrastructure, drilling support assets and other factors as management may deem relevant, such as spacing requirements, easement restrictions and state and local regulations, are considered in determining such locations. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and other factors.

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

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

"*MBOE*"—One thousand BOE.

"*MBOE/D*"—MBOE per day.

"*Mcf*"—One thousand cubic feet of natural gas.

"*MMBtu*"—One million British thermal units.

"*MMcf*"—One million cubic feet of natural gas.

"*Natural gas liquid*"—Components of natural gas that are separated from the gas state in the form of liquids, which include propane, butanes and ethane, among others.

"*Net acres*"—The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"*NYMEX*"—The New York Mercantile Exchange.

"*Productive well*"—A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"*Proved developed non-producing reserves ("PDNP")*"—Developed non-producing reserves.

"*Proved developed reserves ("PDP")*"—Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"*Proved reserves*"—The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

"*Proved undeveloped reserves ("PUD")*"—Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

"*Recompletion*"—The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"*Reservoir*"—A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"*Residue natural gas*"—Natural gas remaining after natural gas liquids extraction.

"*Spacing*"—The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*Standardized measure*"—Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Two stream*"—Production or reserve volumes of oil and wet natural gas, where the natural gas liquids have not been removed from the natural gas stream and the economic value of the natural gas liquids is included in the wellhead natural gas price.

"*Undeveloped acreage*"—Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

"*Unit*"—The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Wellbore*"—The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"*Wellhead natural gas*"—Natural gas produced at or near the well.

"*Working interest*"—The right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this Annual Report on Form 10-K are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal," "should," "intend," "pursue," "target," "continue," "suggest" or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Among the factors that significantly impact our business and could impact our business in the future are:

- the ongoing instability and uncertainty in the U.S. and international financial and consumer markets that is adversely affecting the liquidity available to us and our customers and is adversely affecting the demand for commodities, including crude oil and natural gas;
- volatility of oil and natural gas prices;
- the possible introduction of regulations that prohibit or restrict our ability to apply hydraulic fracturing to our oil and natural gas wells;
- discovery, estimation, development and replacement of oil and natural gas reserves, including our expectations that estimates of our proved reserves will increase;
- competition in the oil and 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 our senior unsecured notes, as well as debt that could be incurred in the future; and
- our ability to generate sufficient cash to service our indebtedness and to generate future profits.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should, therefore, be considered in light of various factors, including those set forth in this Annual Report on Form 10-K under "Item 1A. Risk Factors," in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report on Form 10-K. In light of such risks and uncertainties, we caution you not to place undue reliance on these forward-looking statements. These forward-looking statements speak only as of the date of this Annual Report, or if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities law.

Part I

In this Annual Report on Form 10-K, the consolidated and historical financial information, operational data and reserve information for Laredo and our acquired subsidiary Broad Oak Energy, Inc. ("Broad Oak"), a Delaware corporation, present the assets and liabilities of Laredo Petroleum Holdings, Inc. and its subsidiaries and Broad Oak at historical carrying values and their operations as if they were consolidated for all periods presented prior to July 1, 2011. Although the financial and other information is reported on a consolidated basis, such presentation is not necessarily indicative of the results that would have been obtained if Laredo had owned and operated Broad Oak from its inception. See Note A in our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for more information.

Item 1. *Business*

Overview

Laredo Petroleum Holdings, Inc. (together with its consolidated subsidiaries, "Laredo," "we," "us," "our" or "company") is an independent energy company focused on the exploration, development and acquisition of oil and natural gas 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 134,680 net acres and 37,850 net acres, respectively, as of December 31, 2011. These plays are characterized by high oil and liquids-rich natural gas content, 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 December 31, 2011, we have drilled 29 gross horizontal wells in the Permian and 12 gross horizontal wells in the Anadarko Granite Wash.

Our net cash provided by operating activities was approximately $344 million for the year ended December 31, 2011. Our net average daily production for the same period was approximately 23,709 BOE/D, and our net proved reserves were an estimated 156,453 MBOE.

The following table summarizes total estimated net proved reserves, net acreage and producing wells as of December 31, 2011, and average daily production for the year ended December 31, 2011 in our principal operating regions. Our reserve estimates as of December 31, 2011 are based on a report prepared by Ryder Scott Company, L.P. ("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								Year ended December 31, 2011 average daily production(6)
	Estimated net proved reserves(1)(2)			Identified potential drilling locations(4)			Producing wells		
	MBOE(3)	% of total reserves	% Oil	Total	PUD locations(5)	Net acreage	Gross	Net	(BOE/D)
Permian	101,441	65%	52%	5,669	872	134,680	627	604	14,798
Anadarko Granite Wash	45,101	29%	8%	335	207	37,850	174	130	6,156
Other(7)	9,911	6%	3%	—	—	163,516	352	179	2,755
Total	156,453	100%	36%	6,004	1,079	336,046	1,153	913	23,709

(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 Securities and Exchange Commission ("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") converted at a 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 (33,306 net acres) and Central Texas Panhandle (46,915 net acres), as well as the Dalhart Basin, which is a new exploration effort (83,295 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 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 December 31, 2011, we have a total of 16 operated drilling rigs running. Eleven of these rigs are working on our properties in the Permian Basin, seven of which are drilling vertical wells and four are drilling horizontal wells. Four rigs are operating on our properties in the Anadarko Granite Wash, three of which are drilling horizontal wells, and one is drilling vertical wells. We also have one rig drilling in the Dalhart Basin.

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 petrophysics of the reservoir rock such that it contains hydrocarbons that can be recovered?
- Can the hydrocarbons be produced on a commercial basis?

We carefully assess and monitor all three factors in our drilling and exploration projects. Our drilling activities in areas containing extensive historical industry activity have enabled us to determine whether a prospective reservoir underlies our acreage position, and whether it can be defined both vertically and horizontally. We use a number of proven mapping techniques to understand the physical extent of the targeted reservoir. This includes 2D and 3D seismic data, as well as Laredo owned and historical public well databases (which in the Anadarko Basin may extend back approximately 50 years and in the Permian Basin 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 petrophysics of the rock characteristics prior to the commencement of any completion operations. Finally, after defining the reservoir, our engineers utilize their technical expertise to develop completion programs that we believe will maximize the amount of hydrocarbons that can be recovered. As more wells are completed in the targeted reservoir and additional data becomes available, the process is further refined (and further “de-risked”) in order to minimize costs and maximize recoveries.

As of December 31, 2011, we have 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. We anticipate that in the Anadarko Basin, a majority of these locations will be drilled within the next 5 years, subject primarily to commodity pricing and the continued success of our existing drilling program.

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 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. Based on our currently projected capital expenditure budget, we estimate that by the end of 2013 we will have drilled approximately 347 of these potential locations that were not booked as proved undeveloped as of December 31, 2011. 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 well-spacing requirements and a continuation of the positive results from both our the vertical and horizontal development drilling program.

Our history

Laredo Petroleum Holdings, Inc. was incorporated in August 2011 pursuant to the laws of the State of Delaware for purposes of a corporate reorganization and initial public offering (“IPO”). The corporate reorganization, pursuant to which Laredo Petroleum, LLC was merged with and into Laredo Petroleum Holdings, Inc., with Laredo Petroleum Holdings, Inc. surviving the merger, was completed on December 19, 2011 (the “Corporate Reorganization”). Laredo Petroleum, LLC was formed in 2007 pursuant to the laws of the State of Delaware by affiliates of Warburg Pincus LLC (“Warburg Pincus”), our institutional investor, and the management of Laredo Petroleum, Inc., which was founded in 2006 by Randy A. Foutch, our Chairman and Chief Executive Officer, to acquire, develop and operate oil and gas properties in the Permian and Mid-Continent regions of the United States. In the Corporate Reorganization, all of the outstanding equity interests in Laredo Petroleum, LLC were exchanged for shares of common stock of Laredo Petroleum Holdings, Inc. Laredo Petroleum Holdings, Inc. completed an IPO of its common stock on December 20, 2011. Our business continues to be conducted through Laredo Petroleum, Inc., a wholly-owned subsidiary of Laredo Petroleum Holdings, Inc., and through Laredo Petroleum Inc.’s subsidiaries. The Corporate Reorganization and IPO are discussed in Notes A and D in our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

Laredo Petroleum, Inc. is also the borrower under our senior secured credit facility as well as the issuer of our $550 million senior unsecured notes. Laredo Petroleum Holdings, Inc. and all of its subsidiaries (other than Laredo Petroleum, Inc.) are guarantors of the obligations under our senior secured credit facility and senior unsecured notes.

On July 1, 2011, we completed the acquisition of Broad Oak, which became a wholly-owned subsidiary of Laredo Petroleum, Inc. Broad Oak was formed in 2006 with financial support from its management and Warburg Pincus. On July 19, 2011, we changed the name of Broad Oak to Laredo Petroleum-Dallas, Inc. The 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 65,000 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.

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 Exxon Mobil 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 opportunities, we will continue to evaluate strategically compelling asset acquisitions, mergers and joint ventures within our core areas. Any transaction we pursue will generally complement our asset base and provide a competitive economic proposition relative to our existing opportunities.

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 six 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 December 31, 2011, approximately 58% of our full-time employees are experienced technical employees, including 23 petroleum engineers, 21 geoscientists, 18 landmen and 46 technical support staff.

Economic, multi-year drilling inventory. We have assembled a portfolio of approximately 6,000 gross identified potential drilling locations. 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 December 31, 2011, we have approximately 1,570 square miles of 3D seismic data supporting our exploratory and development drilling programs. From our formation in 2006 through December 31, 2011, we have drilled over 800 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 1,205 to 1,420 Btu per cubic foot and 1,125 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 66 Bbls/MMcf in the Anadarko Granite Wash and our ratio of residue natural gas to wellhead natural gas was 69% and 81%, 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 $58 million in over 230 miles of pipeline in our natural gas gathering systems in the Permian and Anadarko Basins as of December 31, 2011. 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. As of December 31, 2011, we have approximately $627 million available for borrowings under our senior secured credit facility and approximately $635 million (not inclusive of the premium of approximately $2.0 million received on the October 2011 offering of our senior unsecured notes) total debt outstanding, which is 1.6 times our Adjusted EBITDA for the year ended December 31, 2011. We have diversified our capital sources, including raising $319.4 million through the IPO of our common stock in December 2011 and raising $350 million and $200 million in senior unsecured notes in January 2011 and October 2011, respectively. 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.

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 35 miles east of Midland, Texas in Glasscock, Howard, Reagan and Sterling Counties. As of December 31, 2011, we held 134,680 net acres in over 300 sections with an average working interest of 96% in wells drilled as of that 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 December 31, 2011, we have drilled and completed approximately 600 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 four gross horizontal Wolfcamp Shale wells as of December 31, 2011 with encouraging results out of the upper Wolfcamp interval. 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 December 31, 2011, we have drilled a total of 27 gross horizontal wells in the Wolfcamp and Cline formations, of which 23 are in the Cline Shale and four 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 Wolfberry and Cline Shale 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 December 31, 2011, we held 37,850 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 over 150 gross vertical wells.

Our horizontal Granite Wash program is in the development 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 intervals identified as of December 31, 2011, we estimate there are approximately 355 gross identified potential vertical and horizontal drilling locations, all of which are in the Granite Wash.

Other areas

In addition to our Permian Wolfberry 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 December 31, 2011, we held 83,295 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 has been completed and is continually being interpreted. As of December 31, 2011, we have drilled two 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 December 31, 2011, we held 46,915 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 December 31, 2011, we held 33,306 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 significant role in our future if natural gas prices increase.

We expect 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 with improving natural gas prices.

Our operations

Estimated proved reserves

Unless otherwise specifically identified in this Annual Report on Form 10-K, the information with respect to our estimated proved reserves presented below has been prepared by Ryder Scott, our independent reserve engineers, in accordance with the rules and regulations of the SEC applicable to the periods presented. Our net proved reserves 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 assume our ability to fund the capital costs necessary for their development and are impacted by pricing assumptions. See “Item 1A. Risk Factors—Risks related to our business—Estimating reserves and future net revenues involves uncertainties. Decreases in oil and natural gas prices, or negative revisions to reserve estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil and natural gas assets.” 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.

	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. A copy of the summary report prepared by Ryder Scott as of

December 31, 2011 is included as an exhibit to this Annual Report on Form 10-K. 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 Annual Report on Form 10-K. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

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

John E. Minton, our Senior Vice President of Reservoir Engineering, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. He has 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 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 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 "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	For the years ended December 31,		
	2011	2010	2009
Production data:			
Oil (MBbls)	3,368	1,648	513
Natural gas (MMcf)	31,711	21,381	18,302
Oil equivalents (MBOE)(1)(2)	8,654	5,212	3,563
Average daily production (BOE/D)	23,709	14,278	9,762
Revenues (in thousands):			
Oil	$306,481	$126,891	$29,946
Natural gas	$199,774	$112,892	$64,401
Average sales prices without hedges:			
Benchmark oil ($/Bbl)(3)	$ 95.01	$ 79.53	$ 61.79
Realized oil ($/Bbl)(4)	$ 91.00	$ 77.00	$ 58.37
Benchmark natural gas ($/MMBtu)(3)	$ 4.02	$ 4.39	$ 3.98
Realized natural gas ($/Mcf)(4)	$ 6.30	$ 5.28	$ 3.52
Average price ($/BOE)	$ 58.50	$ 46.01	$ 26.48
Average sales prices with hedges(5):			
Oil ($/Bbl)	$ 88.62	$ 77.26	$ 65.42
Natural gas ($/Mcf)	$ 6.67	$ 6.32	$ 6.17
Average price ($/BOE)	$ 58.93	$ 50.37	$ 41.10
Average cost per BOE:			
Lease operating expenses	$ 5.00	$ 4.16	$ 3.52
Production and ad valorem taxes	$ 3.70	$ 3.01	$ 1.72
Depreciation, depletion and amortization	$ 20.38	$ 18.69	$ 16.28
General and administrative	$ 5.19	$ 5.69	$ 5.94

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

(2) 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.

(3) Benchmark oil prices are the simple average of the daily settlement price for NYMEX West Texas Intermediate Light Sweet Crude Oil each month for the period indicated. Benchmark natural gas prices are the simple arithmetic average of the last day settlement price for NYMEX natural gas each month for the period indicated.

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

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

Productive wells

The following table sets forth certain information regarding productive wells in each of our core areas at December 31, 2011. We also own royalty and overriding royalty interests in a small number of wells in which we do not own a working interest.

	Total producing wells				
	Gross				Average working interest
	Vertical	Horizontal	Total(1)	Net	
Permian	601	26	627	604	96%
Anadarko Granite Wash	161	13	174	130	75%
Other(2)	342	10	352	179	51%
Total	1,104	49	1,153	913	79%

(1) 980 of the 1,153 total gross producing wells are Laredo operated.

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

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2011 for each of our core operating areas, including acreage held by production ("HBP"). A majority of our developed acreage is subject to liens securing our senior secured credit facility.

	Developed acres		Undeveloped acres		Total acres		% HBP
	Gross	Net	Gross	Net	Gross	Net	
Permian	78,891	71,124	96,741	63,556	175,632	134,680	53%
Anadarko Granite Wash	31,473	24,276	23,501	13,574	54,974	37,850	64%
Other(1)	91,285	60,983	142,407	102,533	233,692	163,516	37%
Total	201,649	156,383	262,649	179,663	464,298	336,046	47%

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

Undeveloped acreage expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2011 that will expire over the next four years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2012		2013		2014		2015	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian	9,529	4,243	54,496	38,238	16,064	13,340	320	75
Anadarko Granite Wash	7,787	4,393	6,319	3,379	5,231	2,497	640	160
Other(1)	76,633	46,714	25,824	17,351	39,950	38,466	—	—
Total	93,949	55,350	86,639	58,968	61,245	54,303	960	235

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

Drilling activity

The following table summarizes our drilling activity for the three years ended December 31, 2011, 2010 and 2009. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	260	233.2	294	276.6	127	114.7
Dry	0	0.0	2	2.0	2	2.0
Total development wells	260	233.2	296	278.6	129	116.7
Exploratory wells:						
Productive	2	1.4	11	9.3	17	13.7
Dry	0	0.0	1	1.0	2	1.3
Total exploratory wells	2	1.4	12	10.3	19	15.0

Marketing and major customers

We market the majority of production from properties we operate for both our account and the account of the other working interest owners in our operated properties. We sell substantially all of our production to a variety of purchasers under contracts ranging from one month to several years, all at market prices. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. However, based on the current demand for oil and natural gas and the availability of alternate purchasers, we believe that the loss of any one of our major purchasers would not have a material adverse effect on our financial condition and results of operations. For information regarding our customers that accounted for 10% or more of our oil and natural gas revenues during the years of 2011, 2010 and 2009, see Note I in our consolidated financial statements included elsewhere in this Annual Report on Form 10-K. See "Item 1A. Risk Factors—Risks related to our business—The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results."

Title to properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under natural gas leases, or net profits interests.

Oil and natural gas leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 87.5% to 75%. As of December 31, 2011, 47% of our leasehold acreage is held by production.

Seasonality

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

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do, especially in our focus areas. Many of these companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory locations or define, evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory locations and producing natural gas properties.

Hydraulic fracturing

We use hydraulic fracturing as a means to maximize the productivity of almost every well that we drill and complete. Hydraulic fracturing is a necessary part of the completion process for our producing properties in Texas and Oklahoma because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. We are currently conducting hydraulic fracturing activity in the completion of both our vertical and horizontal wells in the Permian Basin and the Anadarko Granite Wash. While hydraulic fracturing is not required to maintain 47% of our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the proved non-producing and proved undeveloped reserves associated with this acreage. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling, recompletion and refracture stimulation projects, or approximately 62% of our total estimated proved reserves as of December 31, 2011, require hydraulic fracturing.

We have and continue to follow standard industry practices and applicable legal requirements. State and federal regulators (including the U.S. Bureau of Land Management on federal acreage) impose requirements on our operations designed to ensure protection of human health and the environment. These protective measures include setting surface casing at a depth sufficient to protect fresh water zones, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This well design effectively eliminates a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval.

Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abrupt change occurred to the injection pressure or annular pressure.

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements.

Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it by discharge into permitted disposal or injection wells, so as to minimize the potential for impact to nearby surface water. We do not discharge water to the surface.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read "—Regulation of environmental and occupational health and safety matters—Water and other waste discharges and spills." For related risks to our stockholders, please read "Item 1A. Risk Factors—Risks related to our business—Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing in our business."

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the Environmental Protection Agency ("EPA"), the Federal Energy Regulatory Commission and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered and such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impacts of compliance.

Regulation of production of oil and natural gas

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. We own interests in properties located onshore in different U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas wells. Some states have the power to prorate production to the market demand for oil and natural gas. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of environmental and occupational health and safety matters

Our operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the EPA, issue regulations, which often require difficult and costly compliance measures, the noncompliance with which carries substantial administrative, civil and criminal penalties and may result in injunctive obligations to remediate noncompliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling, completion and production process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent or mitigate pollution from current or former operations such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses and authorizations, or require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production. Certain of these laws and regulations impose strict and joint and several penalties that could impose liability upon us regardless of fault. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Changes in environmental laws and regulations occur frequently, and to the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects, as well as the oil and natural gas industry in general, could be materially adversely affected.

Hazardous substance and waste handling

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, referred to as CERCLA or the Superfund law, and comparable state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons deemed "responsible parties." These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties. Finally, it is not uncommon for neighboring landowners and other third parties to file common law based claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The Oil Pollution Act of 1990 (the "OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities of $350 million. These liability limits may not apply if: a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a clean-up. We are also subject to analogous state statutes that impose liabilities with respect to oil spills.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. It is possible, however, that these wastes, which could include wastes currently generated during our operations, will be designated as "hazardous wastes" in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as "hazardous wastes." Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We believe that we are in substantial compliance with the requirements of CERCLA, RCRA, OPA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes, or the reinterpretation of current law, could increase our costs to manage and dispose of such wastes.

Water and other waste discharges and spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act ("SDWA"), the OPA and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. The EPA, however, recently asserted federal regulatory authority over hydraulic fracturing under the SDWA's Underground Injection Control ("UIC") Program. Under this assertion of authority, the EPA requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. Although the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decisions as a "final agency action" and, thus, in violation of the notice-and-comment rulemaking procedures of the Administrative Procedures Act. On November 3, 2011, the EPA released its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. The study will include both analysis of existing data and investigative activities designed to generate future data. The EPA intends to release a first report on the results of this study in 2012 and an additional report in 2014 synthesizing the longer-term research projects. In addition, legislation is pending in Congress to repeal the hydraulic fracturing exemption from the SDWA, provide for federal regulation of hydraulic fracturing, and require public disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Finally, on October 20, 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback," as well as "produced water." The EPA asserts that this water may contain radioactive materials and other pollutants and, therefore, may deteriorate drinking water quality if not properly treated before discharge. The Clean Water Act prohibits the discharge of wastewater into federal or state waters. Thus, "flowback" and "produced water" must either be injected into permitted disposal wells, transported to public or private treatment facilities for treatment, or recycled. The EPA asserts that due to some contaminants in hydraulic fracturing wastewater, most treatment facilities are unable to treat the wastewater before introducing it into public waters. If adopted, the new pre-treatment rules will require shale gas operations to pre-treat wastewater before transferring it to treatment facilities. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas. We cannot predict the impact that these standards may have on our business at this time, but these standards could have a material impact on our business, financial condition and results of operation.

A committee of the House of Representatives also is conducting an investigation of hydraulic fracturing practices. Further, certain members of the Congress have called upon: (i) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (ii) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and (iii) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board released a report on August 11, 2011, proposing recommendations to reduce the potential environmental impacts from shale gas production. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism. The U.S. Department of Interior is developing proposed federal regulations to require the disclosure of the chemicals used in the fracturing process going on in public lands and will serve as a model for state regulation regarding the controversial process.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, the chemical components used in the hydraulic fracturing process, as well as the volume of water used, must be disclosed to the Railroad Commission of Texas (the "RRC") and the public beginning February 1, 2012. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

Air emissions

The federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. On August 23, 2011, pursuant to a court ordered consent decree, the EPA published a proposed rule establishing new emissions standards to reduce volatile organic compounds ("VOC") and sulfur dioxide emissions from several types of processes and equipment used in the oil and gas industry, including a 95% reduction in VOCs emitted during construction or modification of hydraulically fractured wells. The EPA received public comment and conducted public hearings regarding the proposed rules and must take final action on them by April 3, 2012. These proposed standards, should they be adopted, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions.

We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Regulation of "greenhouse gas" emissions

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHGs") and including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In response to such studies, Congress has, from time to time, considered legislation to reduce emissions of GHGs. One bill approved by the House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, would have required an 80% reduction in emissions of GHGs from sources within the U.S. between 2012 and 2050, but it was not approved by the U.S. Senate in the 2009-2010 legislative session. Congress is likely to continue to consider similar bills. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs through the planned development of GHG emission inventories and/or regional GHG cap and trade programs or other mechanisms. Most cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles manufactured in model years 2012-2016; however, it does not require immediate reductions in GHG emissions. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011, although it remains the subject of several pending lawsuits filed by industry groups. The tailoring rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the tailoring rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the tailoring rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the tailoring rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Finally, in October 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. The EPA also plans to implement GHG emissions standards for power plants in May 2012 and for refineries in November 2012.

The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

Occupational safety and health act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

National environmental policy act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an environmental assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered species act

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal oil and natural gas leases in areas where certain species that are listed as threatened or endangered and where other species, such as the sage grouse, potentially could be listed as threatened or endangered under the ESA exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. If we were to have a portion of our leases designated as critical or suitable habitat, it could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas, which could adversely impact the value of our leases.

Summary

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2010 or 2011, nor do we anticipate that such expenditures will be material during 2012.

Employees

As of December 31, 2011, we had 186 full-time employees. We also employed a total of 5 part-time employees and 24 contract personnel who assist our full-time employees with respect to specific tasks and perform various field and other services. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Our offices

Our executive office is leased and located at 15 W. Sixth Street, Suite 1800, Tulsa, Oklahoma 74119, and the phone number at this address is (918) 513-4570. We also own or lease field offices in Midland and Dallas, Texas.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol "LPI." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website (http://www.laredopetro.com) all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers, Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating and governance committee are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our executive office at 15 W. Sixth Street, Suite 1800, Tulsa, Oklahoma 74119. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

Item 1A. ***Risk Factors***

Our business involves a high degree of risk. If any of the following risks, or any risks described elsewhere in this Annual Report, were actually to occur, our business, financial condition or results of operations could be materially adversely affected. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial may also adversely affect us.

Risks related to our business

Oil and natural gas prices are volatile. A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for oil and natural gas has been volatile. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic and financial conditions impacting the global supply and demand for oil and natural gas;
- the price and quantity of imports of foreign oil and natural gas, including liquefied natural gas;
- political conditions in or affecting other oil and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- our future cash flow, production and estimated reserves could be adversely affected by further regulatory changes, including any future restrictions on our ability to apply hydraulic fracturing to our wells;
- the level of global oil and natural gas inventories;
- prevailing prices on local oil and natural gas price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Lower oil and natural gas prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves as existing reserves are depleted. Substantial decreases in oil and natural gas prices would render uneconomic a significant portion of our exploration, development and exploitation projects. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, capital contributions or borrowings under our senior secured credit facility or under our senior unsecured notes. Effective upon the Corporate Reorganization, we no longer have any commitments from anyone to contribute any capital to us. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of oil and natural gas and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our oil and natural gas production or reserves, and in some areas a loss of properties.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration, exploitation, development and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production. Our decisions to purchase, explore, develop or otherwise exploit locations or properties will depend in part on the evaluation of information obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Estimating reserves and future net revenues involves uncertainties. Decreases in oil and natural gas prices, or negative revisions to reserve estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil and natural gas assets." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements and related lawsuits, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- fires and blowouts;
- adverse weather conditions, such as hurricanes, blizzards and ice storms;
- declines in oil and natural gas prices;
- limited availability of financing at acceptable rates;
- title problems; and
- limitations in the market for oil and natural gas.

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

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling, recompletion and refracture stimulation projects, or approximately 62% of our total estimated proved reserves as of December 31, 2011, will require hydraulic fracturing. If we are unable to apply hydraulic fracturing to our wells or the process is prohibited or significantly regulated or restricted, we would lose the ability to (i) drill and complete the projects for such proved reserves and (ii) maintain the associated acreage, which would have a material adverse effect on our future business, financial condition, operating results and prospects.

The process is typically regulated by state oil and gas commissions. The U.S. Environmental Protection Agency (the "EPA"), however, recently asserted federal regulatory authority over hydraulic fracturing under the federal Safe Drinking Water Act's ("SDWA") Underground Injection Control ("UIC") Program. Under this assertion of authority, the EPA requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. Industry groups have filed suit challenging the EPA's recent decisions as a "final agency action" and, thus, in violation of the notice-and-comment rulemaking procedures of the Administrative Procedure Act. On November 3, 2011, the EPA released its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. The study will include both analysis of existing data and investigative activities designed to generate future data. The EPA intends to release a first report on the results of this study in 2012 and an additional report in 2014 synthesizing the longer-term research projects. Furthermore, on August 23, 2011, the EPA published a proposed rule in the Federal Register to establish new emissions standards to reduce volatile organic compounds ("VOC") emissions from several types of processes and equipment used in the oil and gas industry, including a 95% reduction in VOCs emitted during the construction or modification of hydraulically fractured wells. In addition, legislation is pending in Congress to repeal the hydraulic fracturing exemption from the SDWA, provide for federal regulation of hydraulic fracturing, and require public disclosure of the chemicals used in the fracturing process. Finally, on October 20, 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback," as well as "produced water." The EPA asserts that this water may contain radioactive materials and other pollutants and, therefore, may deteriorate drinking water quality if not properly treated before discharge. The Clean Water Act prohibits the discharge of wastewater into federal or state waters. Thus, "flowback" and "produced water" must either be injected into permitted disposal wells, transported to public or private treatment facilities for treatment, or recycled. The EPA asserts that due to some contaminants in hydraulic fracturing wastewater, most treatment facilities are unable to treat the wastewater before introducing it into public waters. If adopted, the new pre-treatment rules will require shale gas operations to pre-treat wastewater before transferring it to treatment facilities.

A committee of the House of Representatives is conducting an investigation of hydraulic fracturing practices. Further, certain members of Congress have called upon: (i) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (ii) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and (iii) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board released a report on August 11, 2011, proposing recommendations to reduce the potential environmental impacts from shale gas production. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism. The U.S. Department of Interior is developing proposed federal regulations to require the disclosure of the chemicals used in the fracturing process going on in public lands and will serve as a model for state regulation regarding the controversial process.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, the chemical components used in the hydraulic fracturing process, as well as the volume of water used, must be disclosed to the RRC and the public beginning February 1, 2012. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from conventional or tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

Estimating reserves and future net revenues involves uncertainties. Decreases in oil and natural gas prices, or negative revisions to reserve estimates or assumptions as to future oil and natural gas prices, may lead to decreased earnings, losses or impairment of oil and natural gas assets.

The reserve data included in this Annual Report on Form 10-K represent estimates. Reserve estimation is a subjective process of evaluating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and that relate to projects for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a reasonable time.

The estimation process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil and gas prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also trigger impairment losses on certain properties, which would result in a noncash charge to earnings. See Note P.4 in our audited consolidated financial statements included elsewhere in the Annual Report on Form 10-K.

Our identified potential drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent production prior to the expiration date of leases for such locations. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our identified potential drilling locations.

Our management team has specifically identified and scheduled certain potential drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these potential drilling locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

If commodity prices decrease, we may be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. See Note B.9 to our audited consolidated financial statements included elsewhere in the Annual Report on Form 10-K for additional information.

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

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration, development and exploitation activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future oil and natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Currently, we receive significant incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and oil and natural gas prices do not improve, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2011, we have entered into hedge contracts for approximately 5 million Bbls of our crude oil production and 34 million MMBtu of our natural gas production for settlement between January 2012 and December 2014. We are currently realizing a significant benefit from these hedge positions. If future oil and natural gas prices remain comparable to current prices, we expect that this benefit will decline materially over the life of the hedges, which cover decreasing volumes at declining prices through 2014. If we are unable to enter into new hedge contracts in the future at favorable pricing and for a sufficient amount of our production, our financial condition and results of operations could be materially adversely affected. For additional information regarding our hedging activities, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Commodity derivative financial instruments."

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we enter into derivative instrument contracts for a portion of our oil and natural gas production, including collars, puts and basis swaps. In accordance with applicable accounting principles, we are required to record our derivative financial instruments at fair market value and they are included on our consolidated balance sheet as assets or liabilities and in our consolidated statement of operation as realized or unrealized gains. Losses on derivatives are included in our cash flows from operating activities. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

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

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposure to credit risk is through net joint operations receivables (approximately $24.2 million at December 31, 2011) and the sale of our oil and natural gas production (approximately $49.4 million in receivables at December 31, 2011), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We are generally unable to control which co-owners participate in our wells. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas accounted for approximately

36.1% of our total oil and natural gas revenues for the year ended December 31, 2011. We do not require our customers to post collateral. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial results.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

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

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage and associated clean-up responsibilities;
- regulatory investigations, penalties or other sanctions;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

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

Locations that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. In this Annual Report on Form 10-K, we describe some of our current drilling locations and our plans to explore those drilling locations. Our drilling locations are in various stages of evaluation, ranging from those that are ready to drill to those that will require substantial additional seismic data processing and interpretation before a decision can be made to proceed with the drilling of such locations. There is no way to predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will result in successfully locating oil or natural gas in commercial quantities on our prospective acreage.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures or the amount of hydrocarbons. We employ 3D seismic technology with respect to certain of our projects. The implementation and practical use of 3D seismic technology is relatively new, unproven and unconventional, which can lessen its effectiveness, at least in the near term, and increase our costs. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in our returns. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

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

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

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

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our oil and natural gas exploration, production and gathering operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations. See "Item 1. Business—Regulation of the oil and natural gas industry" for a further description of the laws and regulations that affect us.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development and production activities. These laws and regulations may require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, production and transporting product pipelines or other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, the risk of accidental spills or releases from our operations could expose us to significant liabilities under environmental laws. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected. See "Item 1. Business—Regulation of environmental and occupational health and safety matters" for a further description of the laws and regulations that affect us.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services as well as fees for the cancellation of such services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for and availability of qualified and experienced personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. In particular, the high level of drilling activity in the Permian Basin and Anadarko Granite Wash has resulted in equipment shortages in those areas. We committed to several short-term drilling contracts with various third parties in order to complete various drilling projects. An early termination clause in these contracts requires us to pay significant penalties to the third party should we cease drilling efforts. These penalties could significantly impact our financial statements upon contract termination. As a result of these commitments, approximately $1.6 million in stacked rig fees were incurred in 2009. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. The shortages as well as rig related fees could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938 (the "NGA") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC"). We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline performs a gathering function and therefore is exempt from the FERC's jurisdiction under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is a fact based determination. The classification of facilities as unregulated gathering is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress, which could cause our revenues to decline and operating expenses to increase and may materially adversely affect our business, financial condition or results of operations. In addition, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition or results of operations.

The adoption of climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas we produce

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHGs"), including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In response to such studies, Congress has, from time to time, considered legislation to reduce emissions of GHGs. One bill approved by the House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, would have required an 80% reduction in emissions of GHGs from sources within the U.S. between 2012 and 2050 but was not approved by the Senate in the 2009-2010 legislative session. Congress is likely to continue to consider similar bills. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs, through the planned development of GHG emission inventories and/or regional GHG cap and trade programs or other mechanisms. Most cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles manufactured in model years 2012-2016; however it does not require immediate reductions in GHG emissions. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011, although it remains the subject of several pending lawsuits filed by industry groups and Congress is considering legislation to limit or strip the EPA's authority to regulate GHGs. The tailoring rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the tailoring rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the tailoring rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the tailoring rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Finally, in October 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. The EPA also plans to implement GHG emissions standards for power plants in May 2012 and for refineries in November 2012.

The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

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

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank") provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission, or CFTC, adopt rules or regulations implementing Dodd-Frank and providing definitions of terms used in Dodd-Frank. Dodd-Frank establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities. The CFTC has proposed a large number of rules to implement Dodd-Frank in multiple rulemaking proceedings and has finalized a number of such rules, including a rule imposing position limits (the "Position Limit Rule"). However, many of the regulations necessary to implement Dodd-Frank and define terms used in Dodd-Frank have not been adopted. As a result, we do not yet know if we will be required to comply with margin requirements and clearing and trade-execution requirements imposed by Dodd-Frank or if certain of our counterparties will be required to spin off some of our derivatives contracts to separate entities, which may not be as credit-worthy as our current counterparties. In addition, the International Swaps and Derivatives Association, Inc. and the Securities Industry and Financial Markets Association, two industry associations, have filed a suit in federal court in the District of Columbia against the CFTC challenging the Position Limit Rule. Dodd-Frank and, to the extent that such challenge to the Position Limit Rule is unsuccessful, the Position Limit Rule, and any other new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of Dodd-Frank and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, Dodd-Frank was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of Dodd-Frank and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

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

Laredo acquired Broad Oak in July 2011 with the expectation that the acquisition would result in various benefits, including, among other things, incremental scale and significant additional exposure to attractive vertical and horizontal oil and liquids-rich natural gas opportunities. However, to realize these anticipated benefits, we must successfully integrate Broad Oak into Laredo. If we are not able to achieve these objectives, the anticipated benefits of the acquisition may not be realized fully or at all or may take longer to realize than expected. It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees or the disruption of our ongoing businesses or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, which could adversely affect our ability to achieve the anticipated benefits of the acquisition. Our consolidated results of operations could also be adversely affected by any issues attributable to either company's operations that arise or are based on events or actions that occurred prior to the closing of the acquisition. Laredo may have difficulty addressing possible differences in corporate cultures and management philosophies. Integration efforts will also divert management attention and resources. These integration activities could have an adverse effect on our business during the transition period. The integration process is subject to a number of uncertainties and no assurance can be given regarding when, or even if, the anticipated benefits will be realized. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect Laredo's future business, financial condition, operating results and prospects.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

Our ability to acquire additional locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry, especially in our focus areas. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory locations and to evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could materially adversely affect operations.

We depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Randy A. Foutch, our Chairman and Chief Executive Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

A significant reduction by Warburg Pincus of its ownership interest in us could adversely affect us.

Warburg Pincus is our largest stockholder and two members of our board of directors are affiliates of Warburg Pincus. We believe that Warburg Pincus' substantial ownership interest in us provides them with an economic incentive to assist us to be successful. In connection with the IPO, Warburg Pincus agreed to not sell its shares of common stock until the 180th day after the date of the prospectus, which was December 14, 2011. The underwriters for the IPO may waive this restriction at any time without public notice. After June 11, 2012 or an earlier waiver, Warburg Pincus will not be subject to any obligation to maintain their ownership interest in us and may elect at any time thereafter to sell all or a substantial portion of or otherwise reduce its ownership interest in us. If Warburg Pincus sells all or a substantial portion of its ownership interest in us, Warburg Pincus may have less incentive to assist in our success and its affiliates that are members of our board of directors may resign. Such actions could adversely affect our ability to successfully implement our business strategies which could adversely affect our cash flows or results of operations.

We have limited control over activities on properties we do not operate, which could materially reduce our production and revenues.

A portion of our business activities is conducted through joint operating agreements under which we own partial interests in oil and natural gas properties. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of the underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could materially reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others, therefore, depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells that we do not operate, we may not be in a position to remove the operator in the event of poor performance.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce our cash flow available for drilling and place us at a competitive disadvantage. For example, as of December 31, 2011, we have approximately $627.5 million of additional borrowing capacity under our senior secured credit facility, subject to compliance with financial covenants. The impact of a 1.0% increase in interest rates on an assumed borrowing of the full $712.5 million available under our senior secured credit facility would result in increased annual interest expense of approximately $6.3 million and a corresponding decrease in our net income before the effects of increased interest rates on the value of our interest rate contracts. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in our cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. Our assessment will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis. Even in those circumstances in which we have contractual indemnification rights for pre-closing liabilities, it remains possible that the seller will not be able to fulfill its contractual obligations. Problems with properties we acquire could have a material adverse effect on our business, financial condition and results of operations.

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

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

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

We have incurred losses from operations for various periods since our inception and may do so in the future.

We incurred net losses from our inception to December 31, 2006 of approximately $1.8 million and for each of the years ended December 31, 2007, 2008 and 2009 of approximately $6.1 million, $192.0 million and $184.5 million, respectively. Our financial statements include deferred tax assets, which require management's judgment when evaluating whether they will be realized. Our development of and participation in an increasingly larger number of locations has required and will continue to require substantial capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit and acquire oil and natural gas reserves and realize our deferred tax assets. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical accounting policies and estimates."

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

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. At December 31, 2011, four customers accounted for more than 10% of our oil and gas sales receivables: 32%, 16%, 14% and 11%. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our oil and natural gas hedging arrangements expose us to credit risk in the event of nonperformance by counterparties. Current economic circumstances and the increased bankruptcies may further increase these risks.

We require a significant amount of cash to service our indebtedness. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures depends on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. We cannot assure you that we will generate sufficient cash flow from operations or that future borrowings will be available to us under our senior secured credit facility or otherwise in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness at or before maturity. We cannot assure you that we will be able to refinance any of our indebtedness on commercially reasonable terms or at all.

We may incur significant additional amounts of debt.

As of December 31, 2011, we had total long-term indebtedness of approximately $635 million, not inclusive of the premium of approximately $2.0 million received on the October 2011 offering of our senior unsecured notes. In addition, we may be able to incur substantial additional indebtedness, including secured indebtedness, in the future. The restrictions on the incurrence of additional indebtedness contained in the indenture governing our senior unsecured notes and in our senior secured credit facility are subject to a number of significant qualifications and exceptions, and under certain circumstances, the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If new debt is added to our existing debt levels, the related risks that we face would increase and may make it more difficult to satisfy our existing financial obligations. In addition, the restrictions on the incurrence of additional indebtedness contained in the indenture governing the senior unsecured notes apply only to debt that constitutes indebtedness under the indenture.

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

The indenture governing our senior unsecured 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 all commitments to extend further credit. Such actions by those lenders could cause cross defaults under our other indebtedness, including the senior unsecured notes. If we were unable to repay those amounts, the lenders under our senior secured credit facility could proceed against the collateral granted to them to secure that indebtedness. We pledged a significant portion of our assets as collateral under our senior secured credit facility. If the lenders under our senior secured credit facility accelerate the repayment of the borrowings thereunder, the proceeds from the sale or foreclosure upon such assets will first be used to repay debt under our senior secured credit facility, and we may not have sufficient assets to repay our unsecured indebtedness thereafter.

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and natural gas exploration and development are eliminated as a result of future legislation.

The President's proposed budget for fiscal year 2012 contains a proposal to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and natural gas exploration and development. Any such change could materially adversely affect our financial condition and results of operations by increasing the costs we incur which would in turn make it uneconomic to drill some locations if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure or we are subject to cyberspace breaches or attacks, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Our business could be negatively impacted by security threats, including cyber-security threats, and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a new public company with listed equity securities, we are required to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of

2002, related regulations of the SEC and the requirements of the New York Stock Exchange, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We are required to:

- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

In addition, as a public company, we are subject to these rules and regulations, which could require us to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee, and qualified executive officers.

Risks relating to our common stock

Our amended and restated certificate of incorporation, our bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, our bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- at such time as Warburg Pincus no longer beneficially owns more than 50% of our outstanding common stock, our board of directors will be divided into three classes with each class serving staggered three year terms;
- at such time as Warburg Pincus no longer beneficially owns more than 50% of our outstanding common stock, stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 75% of the voting power of all outstanding voting stock;
- at such time as Warburg Pincus no longer beneficially owns more than 50% of our outstanding common stock, any action by stockholders may no longer be effected by written consent of the stockholders; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

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

Warburg Pincus owns approximately 79.8% of our outstanding shares of common stock. Consequently, Warburg Pincus has significant influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership limits the ability of our other stockholders to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and Warburg Pincus and its affiliates, including its portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. Warburg Pincus LLC is a private equity firm that has invested, among other things, in companies in the energy industry. As a result, Warburg Pincus' existing and future portfolio companies which it controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

We have also renounced our interest in certain business opportunities. Our amended and restated certificate of incorporation provides that, to the fullest extent permitted by applicable law, we renounce any interest or expectancy in any business opportunity, transaction or other matter in which Warburg Pincus or any private fund that it manages or advises, any of their respective officers, directors, partners and employees, and any portfolio company in which such persons or entities have an equity interest (other than us and our subsidiaries) (each, a "specified party") participates or desires or seeks to participate and that involves any aspect of the energy business or industry, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such specified party shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling stockholder or otherwise, by reason of the fact that such specified party pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us. Notwithstanding the foregoing, we do not renounce any interest or expectancy in any business opportunity, transaction or other matter that is offered in writing solely to (i) one of our directors or officers who is not also a specified party or (ii) a specified party who is one of our directors, officers or employees and is offered such business opportunity solely in his or her capacity as our director, officer or employee. By renouncing our interest and expectancy in any business opportunity that from time to time may be presented to Warburg Pincus and its affiliates, our business and prospects could be adversely affected if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

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

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

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

In the future, we may issue securities to raise cash for acquisitions. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

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

Item 3. *Legal Proceedings*

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we have insurance coverage. As of the date hereof, we are not party to any legal proceedings which we currently believe will have a material adverse effect on our business, financial position, results of operations or liquidity.

Item 4. *Mine Safety Disclosures*

Not applicable.

Part II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Market for Registrant's Common Equity. Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "LPI".

The following table sets forth the range of high and low sales prices of our common stock as reported by the NYSE:

2011	High	Low
4th Quarter(1)	$22.31	$17.25

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

Holders. The number of shareholders of record of our common stock was approximately 206 on March 19, 2012.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our senior secured credit facility and the indenture governing our senior unsecured notes restrict the payment of cash dividends on our common stock. See "Item 1A. Risk Factors—Risks related to our business—Our debt agreements contain restrictions that will limit our flexibility in operating our business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation—Cash flows—Debt." We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

On March 19, 2012, the last sale price of our common stock, as reported on the NYSE, was $25.67 per share.

Recent Sales of Unregistered Securities. On December 19, 2011, in connection with the merger of Laredo Petroleum, LLC with and into Laredo Petroleum Holdings, Inc., Laredo Petroleum Holdings, Inc. issued an aggregate of approximately 107,500,000 shares of common stock to the prior unitholders of Laredo Petroleum, LLC in exchange for an aggregate of 215,236,554 equity units in Laredo Petroleum, LLC. Such issuance was exempt from the registration requirements pursuant to Sections 3(a)(9) and 4(2) of the Securities Act.

Use of Proceeds. On December 20, 2011, we completed the IPO of our common stock at price of $17.00 per share pursuant to a Registration Statement on Form S-1, as amended (File No. 333-176439), declared effective by the SEC on December 14, 2011. The underwriters for the offering were J.P. Morgan Securities LLC, Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC, Tudor, Pickering, Holt & Co. Securities, Inc., SG Americas Securities, LLC, Mitsubishi UFJ Securities (USA), Inc., BMO Capital Markets Corp., BNP Paribas Securities Corp., Scotia Capital (USA) Inc., Capital One Southcoast, Inc., BOSC, Inc., BB&T Capital Markets, a division of Scott & Stringfellow, LLC, Comerica Securities, Inc. and Howard Weil Incorporated. Pursuant to the Registration Statement, we registered the offer and sale of 20,125,000 shares of our $0.01 par value common stock, which included 2,625,000 shares subject to an option granted to the underwriters by us to purchase additional shares. The underwriters exercised their option on December 16, 2011. The sale of the shares in our IPO, including the sale of the shares covered by the underwriters' option to purchase additional shares, closed on December 20, 2011. Our IPO terminated upon completion of the closing.

The gross proceeds of our IPO, including the gross proceeds from the underwriters' option to purchase additional shares, based on the IPO price of $17.00 per share, were approximately $342 million, which resulted in net proceeds to Laredo of approximately $319 million after deducting underwriter discounts and commissions and offering expenses of approximately $23 million. No fees or expenses have been paid, directly or indirectly, to any officer, director or 10% stockholder or other affiliate. The net proceeds from our IPO were used to reduce the outstanding borrowings under our senior secured credit facility.

Repurchase of Equity Securities. In connection with our Corporate Reorganization, the three classes of preferred units and certain series of restricted units of Laredo Petroleum, LLC were exchanged into shares of common stock of Laredo Petroleum Holdings, Inc. based on the pre-offering equity value of such units. The conversion of the preferred and restricted units resulted in fractional shares of Laredo Petroleum Holdings, Inc. issued to each respective unit holder, which aggregated to 204 shares of common stock. Laredo Petroleum Holdings, Inc. then purchased all fractional shares at the IPO price of $17.00. These shares are held as treasury stock. See Note A in our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for more information.

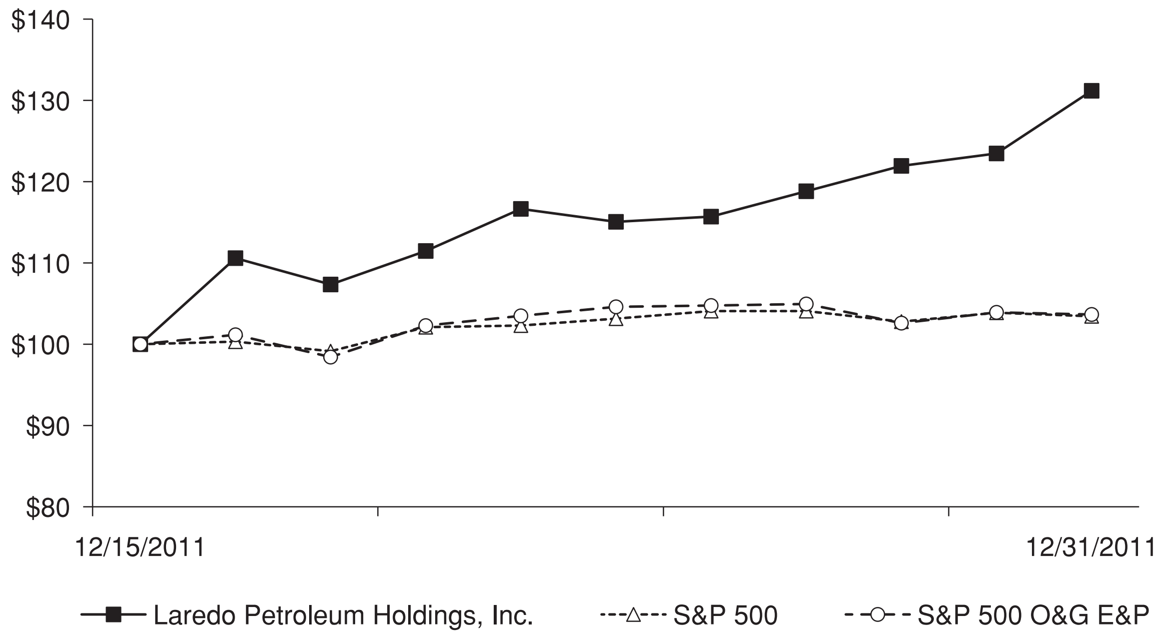
Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
January 1, 2011 - January 31, 2011	—	—	—	—
February 1, 2011 - February 28, 2011	—	—	—	—
March 1, 2011 - March 31, 2011	—	—	—	—
April 1, 2011 - April 30, 2011	—	—	—	—
May 1, 2011 - May 31, 2011	—	—	—	—
June 1, 2011 - June 30, 2011	—	—	—	—
July 1, 2011 - July 31, 2011	—	—	—	—
August 1, 2011 - August 31, 2011	—	—	—	—
September 1, 2011 - September 30, 2011	—	—	—	—
October 1, 2011 - October 31, 2011	—	—	—	—
November 1, 2011 - November 30, 2011	—	—	—	—
December 1, 2011 - December 31, 2011	204	$17.00	—	—
Total	204	$17.00	—	—

Stock Performance Graph. The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph below shows the cumulative total return to our common stockholders from December 15, 2011, the date on which our common stock began trading on the NYSE, through December 31, 2011, as compared to the cumulative five-year total returns on the Standard and Poor's 500 Index ("S&P 500") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P"). The comparison was prepared based upon the following assumptions:

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

2. Dividends, if any, are reinvested.



Item 6. *Selected Historical Financial Data*

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our consolidated financial statements. You should read the following data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report on Form 10-K. We believe that the assumptions underlying the preparation of our financial statements are reasonable. The financial information included in this Annual Report on Form 10-K may not be indicative of our future results of operations, financial position and cash flows.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2011, 2010 and 2009 and the balance sheet data as of December 31, 2011 and 2010 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K. The historical financial data for the year ended December 31, 2008 and the balance sheet data as of December 31, 2009 and 2008 are derived from our audited financial statements not included in this Annual Report on Form 10-K. The historical financial data for the year ended December 31, 2007 and the balance sheet data as of December 31, 2007, are derived from our unaudited financial statements not included in this Annual Report on Form 10-K.

	For the years ended December 31,				
(in thousands, except per share data)	2011	2010	2009	2008(1)	2007(2)
					(unaudited)
Statement of operations data:					
Total revenues	$510,270	$242,000	$ 96,574	$ 74,187	$ 9,628
Total costs and expenses	308,371	169,018	350,103	350,653	17,251
Operating income (loss)	201,899	72,982	(253,529)	(276,466)	(7,623)
Non-operating income (expense), net	(36,971)	(12,546)	(4,972)	30,702	167
Income (loss) before income taxes	164,928	60,436	(258,501)	(245,764)	(7,456)
Net income (loss)	105,554	86,248	(184,495)	(192,047)	(6,051)
Pro forma net income per common share:					
Basic	$ 0.98				
Diluted	$ 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. See Note C in our consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

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

(in thousands)	For the years ended December 31, 2011	2010	2009	2008	2007 (unaudited)
Other financial data:					
Net cash provided by operating activities	$ 344,076	$ 157,043	$ 112,669	$ 25,332	$ 5,019
Net cash used in investing activities	(706,787)	(460,547)	(361,333)	(490,897)	(131,153)
Net cash provided by financing activities	359,478	319,752	250,139	472,140	126,726

(in thousands, unaudited)	For the years ended December 31, 2011	2010	2009	2008	2007
Adjusted EBITDA(1)	$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 commitments and obligations. However, our management team believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;

- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies, and the methods of calculating Adjusted EBITDA and our measurements of Adjusted EBITDA for financial reporting and compliance under our debt agreements differ.

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

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

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes thereto appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, potential failure to achieve production from development projects, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital and financial markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this 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" and "Item 1A. Risk Factors."

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 a Corporate Reorganization and an IPO of our common stock.

Our financial and operating performance for the year ended December 31, 2011 included the following:

- Oil and natural gas sales of approximately $506.3 million, compared to approximately $239.8 million for the year ended December 31, 2010;
- Average daily production of 23,709 BOE/D, compared to 14,278 BOE/D for the year ended December 31, 2010; and
- Estimated net proved reserves of 156,453 MBOE as of December 31, 2011, compared to 136,560 MBOE as of December 31, 2010.

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.

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 Notes A and C in our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K 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. Both of these plays are characterized by high oil and liquids-rich content, multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and significant initial production rates. As of December 31, 2011, we had an interest in 1,153 gross producing wells and, based on a report by Ryder Scott, our independent reserve engineers, as of such date, we operated wells that represent approximately 97% of the value of our proved developed oil and natural gas reserves.

Additionally, as of December 31, 2011, we have accumulated 336,047 net acres with over 6,000 gross identified potential drilling locations on our existing acreage. We intend to develop this large acreage position to increase our cash flow, production and reserves through continued vertical and horizontal drilling programs.

Reserves and pricing

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.

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. 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 "—Sources of our revenue" 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 year ended December 31, 2011, our revenues are comprised of sales of approximately 60% oil, 39% 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. Oil and natural gas prices have historically been volatile. During 2011, West Texas Intermediate Light Sweet Crude Oil prices have been in a range between $85.00 and $110.00 per Bbl and wellhead natural gas market prices have been in a range between $3.14 and $4.37 per MMBtu.

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 and recognize an unrealized gain or loss. 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 December 31, 2011, we entered into six additional derivative contracts to hedge the price risk associated with our oil and gas production. See Note O to our audited consolidated financial statements for additional information regarding these derivative contracts.

Our open positions as of December 31, 2011 are as follows:

	Year 2012	Year 2013	Year 2014
Oil positions(1):			
Puts:			
Hedged volume (Bbls)	672,000	1,080,000	—
Weighted average price ($/Bbl)	$ 65.79	$ 65.00	$ —
Swaps:			
Hedged volume (Bbls)	732,000	600,000	—
Weighted average price ($/Bbl)	$ 93.52	$ 96.32	$ —
Collars:			
Hedged volume (Bbls)	846,000	528,000	528,000
Weighted average floor price ($/Bbl)	$ 75.04	$ 74.55	$ 77.50
Weighted average ceiling price ($/Bbl)	$ 114.50	$ 123.18	$ 125.00
Natural gas positions(2):			
Puts:			
Hedged volume (MMBtu)	4,320,000	6,600,000	—
Weighted average price ($/MMBtu)	$ 5.38	$ 4.00	$ —
Swaps:			
Hedged volume (MMBtu)	1,680,000	—	—
Weighted average price ($/MMBtu)	$ 6.14	$ —	$ —
Collars:			
Hedged volume (MMBtu)	7,800,000	6,600,000	6,960,000
Weighted average floor price ($/MMBtu)	$ 4.12	$ 4.00	$ 4.00
Weighted average ceiling price ($/MMBtu)	$ 5.79	$ 7.05	$ 7.03
Basis Swaps:			
Hedged volume (MMBtu)	2,880,000	1,200,000	—
Weighted average price ($/MMBtu)	$ 0.31	$ 0.33	$ —

(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.

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 (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.

Results of operations

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.

(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 volumes			$186,982
Rounding differences			$ (7)
Total change in revenues			$266,472

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

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

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

Lease operating expenses. Lease operating expenses, which include workover expenses, increased to $43.3 million for the year ended December 31, 2011 from $21.7 million for the year ended December 31, 2010, an increase of approximately 100%. The increase was primarily due to an increase in drilling activity, which resulted in additional producing wells during 2011 compared to 2010. On a per-BOE basis, lease operating expenses increased in total to $5.00 per BOE at December 31, 2011 from $4.16 per BOE at December 31, 2010. The majority of the increase is due to approximately $3.5 million in additional workover expenses incurred during 2011 as compared to the same period in 2010 as market conditions for oil and gas became more favorable.

Production and ad valorem taxes. Production and ad valorem taxes increased to approximately $32.0 million for the year ended December 31, 2011 from $15.7 million for the year ended December 31, 2010, an increase of $16.3 million, or approximately 104%, primarily due to the increase in market prices (not including the effects of hedging), as well as a 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 our senior unsecured notes, the Broad Oak acquisition, the filing of a registration statement relating to our senior unsecured notes with the SEC and other matters accounted for approximately $7.4 million, or 48%, of the change in G&A, as well as approximately $7.2 million in additional salary, benefits and bonus expenditures due to the Broad Oak acquisition and the growth of our business and employee base. On a per-BOE basis, G&A expense 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 future periods. See Note O to our audited consolidated financial statements included elsewhere in the Annual Report on Form 10-K for additional information.

Depreciation, depletion and amortization ("DD&A"). DD&A increased to approximately $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 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.

Subsequent to December 31, 2011, we entered into six additional derivatives contracts to hedge price volatility on our oil and natural gas production. Two of the six additional contracts have associated deferred premiums which total approximately $1.3 million. Of the $1.3 million in deferred premiums, approximately $0.4 million is due in 2014 and $0.9 million is due in 2015. See Note O of our audited consolidated financial statements included elsewhere in the Annual Report on Form 10-K for additional information regarding derivatives contracts entered into subsequent to 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 our senior unsecured notes during 2011 as compared to 2010 as shown in the table below. Additionally, we had approximately $3.5 million in amortized deferred loan costs and $0.7 million in other fees and deferred option premium amortization that were charged to interest expense for the year ended December 31, 2011 as compared to $2.0 million in amortized deferred loan costs and $0.4 million in other fees and deferred option premium amortization for the year ended December 31, 2010.

	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%
Senior unsecured notes	392,319	8.98%	—	—
Term loan(1)	100,000	0.51%	100,000	4.49%
Broad Oak credit facility(2)	122,904	3.07%	123,782	4.27%

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

(2) The Broad Oak credit facility was paid-in-full and terminated on July 1, 2011 in conjunction 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 our senior unsecured notes to pay in full and retire our term loan. Additionally, concurrent with the issuance of our senior unsecured notes, the borrowing base on our senior secured credit facility was lowered from $220.0 million to $200.0 million. As a result, we took a charge to expense for the debt issuance costs attributable to our term loan and a proportionate percentage of the costs incurred for our senior secured credit facility, which totaled $2.9 million and $0.3 million, respectively. As of December 31, 2011, the borrowing base on our senior secured credit facility is $712.5 million. On July 1, 2011, in conjunction with the Broad Oak acquisition, the Broad Oak credit facility was paid in full and terminated and the related debt issuance costs of $2.9 million were charged to expense.

Income tax expense. We 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.

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.

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.

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.

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 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 conjunction 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 likely than not that we would not realize a future benefit for the full amount of the federal and Louisiana net deferred tax asset as of December 31, 2009.

Liquidity and capital resources

Our primary sources of liquidity have been capital contributions from Warburg Pincus, certain members of our management and our board of directors, borrowings under our senior secured credit facility, our senior unsecured 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 for our planned exploration and development activities. In addition, our hedge positions currently provide relative certainty on a majority of our cash flows from operations through 2012 even with the general decline in the prices of natural gas.

Through December 19, 2011, a total of approximately $1.2 billion in equity had been invested in us (including through investments in Broad Oak) by Warburg Pincus, certain members of management and our independent directors. In conjunction with our Corporate Reorganization, the equity invested in us by Warburg Pincus was exchanged for 101,884,117 vested shares of our common stock and we no longer have any commitment from Warburg Pincus to contribute any capital to us.

At December 31, 2011, we had approximately $85.0 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 senior unsecured notes, excluding the premium of $2.0 million received on the October 2011 offering of our senior unsecured notes. Additionally, we had approximately $627.5 million available for borrowing under our senior secured credit facility at December 31, 2011. We believe such availability as well as cash flows from operations and cash on hand provide us with the ability to implement our planned exploration and development activities.

As of March 19, 2012 we had approximately $230.0 million in debt outstanding and $482.5 million available for borrowings under our senior secured credit facility.

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 "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below.

Cash flows

Our cash flows for the years ended December 31, 2011, 2010 and 2009 are as follows:

	Years ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Net cash provided by operating activities	$ 344,076	$ 157,043	$ 112,669
Net cash used in investing activities	(706,787)	(460,547)	(361,333)
Net cash provided by financing activities	359,478	319,752	250,139
Net increase (decrease) in cash	$ (3,233)	$ 16,248	$ 1,475

Cash flows provided by operating activities

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 throughout 2011, 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 "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Cash flows used in investing activities

We had cash flows used in investing activities of approximately $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 acquisitions and capital expenditures for the years ended December 31, 2011, 2010 and 2009 is summarized in the table below.

	Years ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Acquisition of oil and gas properties	$ —	$ —	$ —
Restricted cash	—	—	2,201
Capital expenditures:			
Oil and gas properties	(687,062)	(454,161)	(340,636)
Pipeline and gathering assets	(13,368)	(4,277)	(19,995)
Other fixed assets	(6,413)	(2,198)	(3,071)
Proceeds from other asset disposals	56	89	168
Net cash used in investing activities	$(706,787)	$(460,547)	$(361,333)

Capital expenditure budget

Our board of directors approved a budget of $757 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 $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 our senior unsecured notes of $350.0 million on January 20, 2011 and $202.0 million on October 11, 2011, net proceeds from our IPO of $319.4 million, net reductions of our senior secured credit facility and former Broad Oak credit facility totaling $306.6 million, the payment of $100.0 million to pay in full and terminate our term loan and payments of $23.2 million for loan costs. Additionally, we incurred approximately $82.0 million in debt to facilitate the Broad Oak acquisition.

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

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

Debt

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

Senior secured credit facility. Laredo Petroleum, Inc. is the borrower under our senior secured credit facility, which was amended and restated as of July 29, 2008, amended in December 2008, May 2009 and November 2009, amended and restated as of July 7, 2010, amended as of January 20, 2011, amended and restated as of July 1, 2011 and amended as of October 11, 2011. We used the net proceeds from our January 2011 offering of our senior unsecured notes, among other things, to pay down all loan amounts outstanding under the senior secured credit facility, which totaled approximately $177.5 million at December 31, 2010. Additionally, we used the net proceeds from our October 2011 offering of our senior unsecured notes and the net proceeds from our IPO in December 2011 to pay down the outstanding loan amounts on our senior secured credit facility. Refer to Note C of our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for further discussion of the January 2011 and October 2011 offerings of our senior unsecured notes, our IPO and use of proceeds related thereto.

On July 1, 2011, in conjunction with the Broad Oak acquisition, we entered into an amendment and restatement of our senior secured credit facility that provided for (i) the replacement of Bank of America, N.A. as the administrative agent with Wells Fargo Bank, N.A., (ii) the repayment of amounts outstanding under the Broad Oak credit facility, (iii) an extension of the maturity date of our senior secured credit facility by one year to July 1, 2016, (iv) an increase in the facility capacity to $1.0 billion and an increase in the borrowing base of our senior secured credit facility to $650.0 million and (v) a reduction in the applicable margins for Eurodollar Tranches to between 1.75% and 2.75% and for Adjusted Base Rate Tranches to between 0.75% and 1.75% based on the ratio of outstanding revolving credit to the conforming borrowing base. The borrowing base was subsequently increased to $712.5 million on October 28, 2011. Refer to Notes A and C of our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for further discussion of the Broad Oak acquisition and the amendment and restatement of our senior secured credit facility. The amendment entered into on October 11, 2011 allowed for the issuance of an additional $200.0 million of our senior unsecured notes discussed below. Refer to Note C of our audited consolidated financial statements presented elsewhere in this Annual Report on Form 10-K for further discussion of this amendment.

Principal amounts borrowed under the senior secured credit facility are payable on the final maturity date with such borrowings bearing interest that is payable, at our election, either on the last day of each fiscal quarter at an Adjusted Base Rate or at the end of one-, two-, three-, six- or, to the extent available, twelve-month interest periods (and in the case of six- and twelve-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate ("LIBOR"), in each case, plus an applicable margin based on the ratio of outstanding senior secured credit to the borrowing base. At December 31, 2011, the applicable margin rates were 0.75% for the adjusted base rate advances and 1.75% for the Eurodollar advances. The amount of the senior secured credit facility outstanding at December 31, 2011 was subject to an interest rate of approximately 2.06%. We are also required to pay an annual commitment fee on the unused portion of the bank's commitment of 0.5%.

As of December 31, 2011, 2010 and 2009, borrowings outstanding under our senior secured credit facility totaled $85.0 million, $177.5 million and $202.5 million, respectively. As of March 19, 2012, the outstanding balance under our senior secured credit facility was $230.0 million.

Our senior secured credit facility is secured by a first priority lien on our assets (including stock of Laredo Petroleum, Inc.), including oil and natural gas properties constituting at least 80% of the present value of our proved reserves owned now or in the future. At December 31, 2011, we were subject to the following financial and non-financial ratios on a consolidated basis:

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

Our senior secured credit facility contains both financial and non-financial covenants. We were in compliance with these covenants at December 31, 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;
- enter into transactions with affiliates;
- engage in certain transactions that violate ERISA or the Internal Revenue Code or enter into certain employee benefit plans and transactions;
- enter into certain swap agreements or hedge transactions;
- incur, become or remain liable under any operating lease which would cause rentals payable to be greater than $10.0 million in a fiscal year;
- acquire all or substantially all of the assets or capital stock of any person, other than assets consisting of oil and natural gas properties and certain other oil and natural gas related acquisitions and investments; and

- repay or redeem our senior unsecured notes, or amend, modify or make any other change to any of the terms in our senior unsecured notes that would change the term, life, principal, rate or recurring fee, add call or pre-payment premiums, or shorten any interest periods.

As of December 31, 2011, we were in compliance with the terms of our senior secured credit facility. If an event of default exists under our senior secured credit facility, the lenders will be able to accelerate the maturity of our senior secured credit facility and exercise other rights and remedies. As of December 31, 2011, 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.

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 December 31, 2011, we had one letter of credit outstanding totaling approximately $0.03 million under 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 Annual Report on Form 10-K 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 and $200 million 9½% senior unsecured notes due 2019, respectively. Our senior unsecured notes will mature on February 15, 2019 and bear an interest rate of 9½% per annum, payable semi-annually, in cash in arrears on February 15 and August 15 of each year, commencing August 15, 2011. Our senior unsecured notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by Laredo Petroleum Holdings, Inc. and its subsidiaries (other than Laredo Petroleum, Inc.) (collectively, the "guarantors"). The net proceeds from our senior unsecured notes were used (i) to repay and retire $100.0 million outstanding under our prior term loan facility, (ii) to pay approximately $377.5 million of the outstanding borrowings under our senior secured credit facility and (iii) for general working capital purposes. Our senior unsecured notes were issued under and are governed by an indenture dated January 20, 2011, among Laredo Petroleum, Inc., Wells Fargo Bank, National Association, as trustee, and the guarantors. The indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of dividends or similar restricted payments, entering into transactions with affiliates and limitations on asset sales. Indebtedness under our senior unsecured notes may be accelerated in certain circumstances upon an event of default as set forth in the indenture.

Laredo Petroleum, Inc. may redeem all or a portion of our senior unsecured 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 our senior unsecured 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 our senior unsecured 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 our senior unsecured 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 our senior unsecured notes (including the principal amount of any additional notes) issued under the indenture 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 our senior unsecured notes upon a change of control triggering event.

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

On December 19, 2011, prior to the closing of our Corporate Reorganization, we entered into a second supplemental indenture and a third supplemental indenture pursuant to which Laredo Petroleum Holdings, Inc. was added as a guarantor under the indenture dated as of January 20, 2011 and agreed to assume all of the obligations of the parent guarantor under the indenture, respectively.

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 December 31, 2011, the principal on our senior secured credit facility is due on July 1, 2016.

(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 Annual Report on Form 10-K for additional discussion of our drilling contract commitments.

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

(4) Amounts represent our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment.

See Note B to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

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

Critical accounting policies and estimates

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

Method of accounting for oil and natural gas properties

The accounting for our business is subject to special accounting rules that are unique to the oil and 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.

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. 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.

Income taxes

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

Recent accounting pronouncements

In May 2011, the FASB issued Accounting Standards Update ("ASU") 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,* which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and International Financial Reporting Standards. This new guidance changes some fair value measurement principles and disclosure requirements, but does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. The update is effective for annual periods beginning after December 15, 2011 and we have implemented it in this Annual Report on Form 10-K.

In December 2011, the FASB issued 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 are in the process of evaluating the impact, if any, the adoption of this update will have 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 year ended December 31, 2011. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and we do experience inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which we operate.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements other than operating leases, which are included in "—Obligations and commitments."

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in oil and 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 "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Hedging."

Interest rate risk. As part of our senior secured credit facility, we have debt which bears interest at a floating rate. For the year ended December 31, 2011, the weighted average indebtedness outstanding on our senior secured credit facility bore a weighted average interest rate of 2.07%. Based on the total outstanding borrowings under this facility at December 31, 2011 of $85.0 million, a 1.0% increase in each of the average LIBOR rates and federal funds rates would result in an estimated $0.9 million increase in interest expense for the year ended December 31, 2011 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 December 31, 2011, we had interest rate swaps and one interest rate cap outstanding for a notional amount of $260.0 million with fixed pay rates ranging from 1.11% to 3.41% and terms expiring 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 $19.8 million at December 31, 2011), joint interest receivables (approximately $24.2 million at December 31, 2011) and the receivables from the sale of our oil and natural gas production (approximately $49.4 million at December 31, 2011), 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 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. At December 31, 2009, we had two customers that made up approximately 43% and 17% of our total oil and gas sales accounts receivable, respectively.

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 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. At December 31, 2009, we had two interest owners that made up approximately 38% and 23% of our total joint operations receivables.

Refer to Note I of our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K for additional disclosures regarding credit risk.

Item 8. ***Financial Statements and Supplementary Data***

Our consolidated financial statements and supplementary financial data are included in this Annual Report beginning on page F-1.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2011 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

This Annual Report on Form 10-K does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of Laredo's independent registered public accounting firm due to a transition period established by SEC rules for newly public companies. A report of management's assessment regarding internal control over financial reporting and an attestation on the effectiveness of our internal control over financial reporting by our independent registered public accounting firm are not required until we file our annual report for the year ended December 31, 2012.

Item 9B. ***Other Information***

None.

Part III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Information regarding our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers and Corporate Governance Guidelines for our principal executive officer and principal financial and accounting officer are described in "Item 1. Business" in this Annual Report on Form 10-K. Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 10 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2011.

Item 11. ***Executive Compensation***

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 11 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2011.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 12 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2011.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 13 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2011.

Item 14. ***Principal Accounting Fees and Services***

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 14 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2011.

Part IV

Item 15. *Exhibits, Financial Statement Schedules*

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 of this Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Consolidated Financial Statements" on page F-1 of this Annual Report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

Exhibit Number	Description
2.1	Agreement and Plan of Merger by and between Laredo Petroleum, LLC and Laredo Petroleum Holdings, Inc. dated as of December 19, 2011 (incorporated by reference to Exhibit 2.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
3.1	Amended and Restated Certificate of Incorporation of Laredo Petroleum Holdings, Inc. (incorporated by reference to Exhibit 3.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
3.2	Amended and Restated Bylaws of Laredo Petroleum Holdings, Inc. (incorporated by reference to Exhibit 3.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of Laredo's Registration Statement on Form S-1/A (File No. 333-176439) filed on November 14, 2011).
4.2	Indenture dated as of January 20, 2011 among Laredo Petroleum, Inc., the several guarantors named therein, and Wells Fargo Bank, National Association, as trustee. (incorporated by reference to Exhibit 4.2 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
4.3	Supplemental Indenture dated as of July 20, 2011, among Laredo Petroleum, Inc. Laredo Petroleum—Dallas, Inc., the guarantors listed on Schedule A thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
4.4	Second Supplemental Indenture dated as of December 19, 2011 among Laredo Petroleum, Inc., Laredo Petroleum Holdings, Inc., the guarantors listed on Schedule A thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
4.5	Third Supplemental Indenture dated as of December 19, 2011 among Laredo Petroleum, Inc., Laredo Petroleum Holdings, Inc., the guarantors listed on Schedule A thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 10.3 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).

Exhibit Number	Description
4.6	Registration Rights Agreement dated as of January 20, 2011 among Laredo Petroleum, Inc., the several guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 of Laredo's Registration Statement on From S-4 (File No. 333-173984) filed on May 5, 2011).
4.7	Registration Rights Agreement dated as of October 19, 2011 among Laredo Petroleum, Inc., the several guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.4 of Laredo's Registration Statement on From S-4/A (File No. 333-173984-05) filed on December 12, 2011).
10.1	Third Amended and Restated Credit Agreement dated as of July 1, 2011 among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as Administrative Agent, Bank of America, N.A. and JPMorgan Chase Bank, N.A., as Co-Syndication Agents, Societe Generale, Union Bank, N.A. and BMO Harris Financing, Inc., as Co-Documentation Agents, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and the financial institutions listed on Schedule I thereto (incorporated by reference to Exhibit 10.1 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
10.2	First Amendment to Third Amended and Restated Credit Agreement, dated as of October 11, 2011, among Laredo Petroleum, Inc., each of the guarantors thereto, each of the banks signatories thereto, and Wells Fargo Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.4 of Laredo's Registration Statement on Form S-1A (File No. 333-176439) filed on November 14, 2011).
10.3	Limited Consent and Second Amendment to Third Amended and Restated Credit Agreement, dated as of November 23, 2011, among Laredo Petroleum, Inc., Wells Fargo Bank, N.A., as administrative agent, the guarantors signatories thereto and the banks signatories thereto (incorporated by reference to Exhibit 10.3 of Laredo's Registration Statement on From S-4/A (File No. 333-173984-05) filed on December 12, 2011).
10.4	Contribution Agreement, dated as of June 15, 2011, by and among Broad Oak Energy, Inc., Warburg Pincus Private Equity IX, L.P., the other persons listed as Contributors on the signature pages thereto and Laredo Petroleum, LLC (incorporated by reference to Exhibit 10.2 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
10.5	Stock Purchase and Sale Agreement, dated as of June 15, 2011, by and among Laredo Petroleum, Inc. and the individuals listed as Sellers on the signature pages thereto (incorporated by reference to Exhibit 10.3 of Laredo's Registration Statement on Form S-1 (File No. 333-176439) filed on August 24, 2011).
10.6	Form of Registration Rights Agreement dated December 20, 2011 among Laredo Petroleum Holdings, Inc. and the signatories thereto (incorporated by reference to Exhibit 10.5 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
10.7#	Form of Indemnification Agreement between Laredo Petroleum Holdings, Inc. and each of the officers and directors thereof (incorporated by reference to Exhibit 10.6 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
10.8#	Laredo Petroleum Holdings, Inc. 2011 Omnibus Equity Incentive Plan (incorporated by reference to Exhibit 10.4 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).

Exhibit Number	Description
10.9#	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.10#	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.11#	Form of Performance Compensation Award Agreement (incorporated by reference to Exhibit 10.3 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on February 9, 2012).
10.12	Laredo Petroleum Holdings, Inc. Change in Control Executive Severance Plan Certificate (incorporated by reference to Exhibit 10.7 of Laredo's Registration Statement on Form S-1/A (File No. 333-176439) filed on November 14, 2011).
21.1*	List of Subsidiaries of Laredo Petroleum Holdings, Inc.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Summary Report of Ryder Scott Company, L.P.

* Filed herewith.

** Furnished herewith.

\# Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

LAREDO PETROLEUM HOLDINGS INC.

By: /s/ RANDY A. FOUTCH

Randy A. Foutch
Chief Executive Officer

Date: March 20, 2012

KNOWN ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Randy A. Foutch, W. Mark Womble and Kenneth E. Dornblaser, each of whom may act without joinder of the other, as their true and lawful attorneys-in-fact and agents, each with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ RANDY A. FOUTCH Randy A. Foutch	Chairman and Chief Executive Officer (principal executive officer)	March 20, 2012
/s/ W. MARK WOMBLE W. Mark Womble	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	March 20, 2012
/s/ JERRY R. SCHUYLER Jerry R. Schuyler	Director, President and Chief Operating Officer	March 20, 2012
/s/ PETER R. KAGAN Peter R. Kagan	Director	March 20, 2012

Signatures	Title	Date
/s/ JAMES R. LEVY James R. Levy	Director	March 20, 2012
/s/ B.Z. (BILL) PARKER B.Z. (Bill) Parker	Director	March 20, 2012
/s/ PAMELA S. PIERCE Pamela S. Pierce	Director	March 20, 2012
/s/ AMBASSADOR FRANCIS ROONEY Ambassador Francis Rooney	Director	March 20, 2012
/s/ EDMUND P. SEGNER, III Edmund P. Segner, III	Director	March 20, 2012
/s/ DONALD D. WOLF Donald D. Wolf	Director	March 20, 2012

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Laredo Petroleum Holdings, Inc.

We have audited the accompanying consolidated balance sheets of Laredo Petroleum Holdings, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, stockholders' equity/unit holders' equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Laredo Petroleum Holdings, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
March 20, 2012

Laredo Petroleum Holdings, Inc.
Consolidated balance sheets
December 31, 2011 and 2010
(in thousands, except units and share data)

	2011	2010
Assets		
Current assets:		
Cash and cash equivalents	$ 28,002	$ 31,235
Accounts receivable, net	74,135	43,939
Derivative financial instruments	13,281	8,376
Deferred income taxes	5,202	11,229
Other current assets	2,318	5,637
Total current assets	122,938	100,416
Property and equipment:		
Oil and natural gas properties, full cost method:		
Proved properties	2,083,015	1,379,885
Unproved properties not being amortized	117,195	96,515
Pipeline and gas gathering assets	58,136	43,271
Other fixed assets	16,948	10,869
	2,275,294	1,530,540
Less accumulated depreciation, depletion, amortization and impairment	896,785	720,647
Net property and equipment	1,378,509	809,893
Deferred income taxes	90,376	143,723
Derivative financial instruments	6,510	1,804
Deferred loan costs, net	23,457	10,353
Other assets, net	5,862	1,971
Total assets	$1,627,652	$1,068,160
Liabilities and stockholders' equity/unit holders' equity		
Current liabilities:		
Accounts payable	$ 46,007	$ 41,338
Undistributed revenue and royalties	26,844	10,664
Accrued capital expenditures	91,022	65,900
Accrued compensation and benefits	11,270	8,778
Derivative financial instruments	4,187	11,978
Accrued interest payable	20,112	1,542
Other current liabilities	14,919	10,043
Total current liabilities	214,361	150,243
Long-term debt	636,961	491,600
Derivative financial instruments	2,415	5,987
Asset retirement obligations	12,568	7,547
Other noncurrent liabilities	1,334	1,684
Total liabilities	867,639	657,061
Unit holders' equity:		
Preferred units, zero and 99,870,000 units issued at December 31, 2011 and 2010, respectively	—	549,187
Restricted units, zero and 31,432,000 units issued at December 31, 2011 and 2010, respectively	—	4,504
Other equity interests	—	155,596
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero outstanding at December 31, 2011 and 2010	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized, and 127,617,391 and zero outstanding at December 31, 2011 and 2010, respectively	1,276	—
Additional paid-in capital	951,375	—
Accumulated deficit	(192,634)	(298,188)
Less treasury stock, at cost, 7,609 and zero common shares at December 31, 2011 and 2010, respectively	(4)	—
Total stockholders' equity/unit holders' equity	760,013	411,099
Total liabilities and stockholders' equity/unit holders' equity	$1,627,652	$1,068,160

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

Laredo Petroleum Holdings, Inc.

Consolidated statements of operations

For the years ended December 31, 2011, 2010 and 2009

(in thousands, except for per share data)

	2011	2010	2009
Revenues:			
Oil and natural gas sales	$506,255	$239,783	$ 94,347
Natural gas transportation and treating	4,015	2,217	2,227
Total revenues	510,270	242,000	96,574
Costs and expenses:			
Lease operating expenses	43,306	21,684	12,531
Production and ad valorem taxes	31,982	15,699	6,129
Natural gas transportation and treating	977	2,501	1,416
Drilling rig fees	—	—	1,606
Drilling and production	3,817	340	758
General and administrative	44,953	29,651	21,164
Equity and stock-based compensation	6,111	1,257	1,419
Accretion of asset retirement obligations	616	475	406
Depreciation, depletion and amortization	176,366	97,411	58,005
Impairment expense	243	—	246,669
Total costs and expenses	308,371	169,018	350,103
Operating income (loss)	201,899	72,982	(253,529)
Non-operating income (expense):			
Realized and unrealized gain (loss):			
Commodity derivative financial instruments, net	21,047	11,190	5,744
Interest rate derivatives, net	(1,311)	(5,375)	(3,394)
Interest expense	(50,580)	(18,482)	(7,464)
Interest and other income	108	151	227
Write-off of deferred loan costs	(6,195)	—	—
Loss on disposal of assets	(40)	(30)	(85)
Non-operating expense, net	(36,971)	(12,546)	(4,972)
Income (loss) before income taxes	164,928	60,436	(258,501)
Income tax (expense) benefit:			
Deferred	(59,374)	25,812	74,006
Total income tax (expense) benefit, net	(59,374)	25,812	74,006
Net income (loss)	$105,554	$ 86,248	$(184,495)
Pro forma net income per common share:			
Basic	$ 0.98		
Diluted	$ 0.98		
Pro forma weighted average common shares outstanding:			
Basic	107,187		
Diluted	108,099		

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

Laredo Petroleum Holdings, Inc.

Consolidated statements of stockholders' equity/unit holders' equity

For the years ended December 31, 2011, 2010 and 2009

(in thousands)

	Series A		BOE Preferred		Restricted Units			Common Stock		Additional paid-in capital	Treasury Stock (at cost)		Other equity interests	Accumulated deficit	Total
	Units	Amount	Units	Amount	Units	Amount	Treasury Units	Shares	Amount		Shares	Amount			
Balance, December 31, 2008	76,000	$ 399,820	—	$ —	16,537	$ 1,864	$ —	—	$ —	$ —	—	$—	$ 116,621	$(199,941)	$ 318,364
Issuance of equity interests	20,000	125,000	—	—	—	—	—	—	—	—	—	—	29,581	—	154,581
Purchase of equity interests	—	—	—	—	—	—	(300)	—	—	—	—	—	(632)	—	(932)
Cancellation of Series A Units	(48)	(120)	—	—	—	—	300	—	—	—	—	—	—	—	180
Equity-based compensation	—	—	—	—	10,694	1,419	—	—	—	—	—	—	—	—	1,419
Purchase of restricted units	—	—	—	—	—	—	(10)	—	—	—	—	—	—	—	(10)
Cancellation of restricted units	—	—	—	—	(272)	(10)	10	—	—	—	—	—	—	—	—
Net loss	—	—	—	—	—	—	—	—	—	—	—	—	—	(184,495)	(184,495)
Balance, December 31, 2009	95,952	524,700	—	—	26,959	3,273	—	—	—	—	—	—	145,570	(384,436)	289,107
Issuance of equity interests	4,000	25,000	—	—	—	—	—	—	—	—	—	—	10,000	—	35,000
Purchase of equity interests	—	—	—	—	—	—	(513)	—	—	—	—	—	—	—	(513)
Cancellation of Series A Units	(82)	(513)	—	—	—	—	513	—	—	—	—	—	—	—	—
Equity-based compensation	—	—	—	—	6,286	1,231	—	—	—	—	—	—	26	—	1,257
Cancellation of restricted units	—	—	—	—	(1,813)	—	—	—	—	—	—	—	—	—	—
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—	86,248	86,248
Balance, December 31, 2010	99,870	549,187	—	—	31,432	4,504	—	—	—	—	—	—	155,596	(298,188)	411,099
Purchase of equity interests	—	—	—	—	—	—	(125)	—	—	—	—	—	—	—	(125)
Cancellation of Series A Units	(20)	(125)	—	—	—	—	125	—	—	—	—	—	—	—	—
Equity-based compensation	—	—	—	—	9,859	5,829	—	—	—	—	—	—	132	—	5,961
Purchase of restricted units	—	—	—	—	—	—	(38)	—	—	—	—	—	—	—	(38)
Cancellation of restricted units	—	—	—	—	(1,389)	(37)	38	—	—	—	—	—	—	—	1
Broad Oak Transaction	—	—	88,986	73,765	—	—	—	—	—	—	—	—	(155,728)	—	(81,963)
Common shares issued upon Corporate Reorganization	(99,850)	(549,062)	(88,986)	(73,765)	(39,902)	(10,296)	—	107,500	1,075	632,048	—	—	—	—	—
Common shares issued at initial public offering, net of offering costs	—	—	—	—	—	—	—	20,125	201	319,177	—	—	—	—	319,378
Stock-based compensation	—	—	—	—	—	—	—	—	—	150	—	—	—	—	150
Shares repurchased	—	—	—	—	—	—	—	(8)	—	—	8	(4)	—	—	(4)
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—	105,554	105,554
Balance, December 31, 2011	—	$ —	—	$ —	—	$ —	$ —	127,617	$1,276	$951,375	8	$ (4)	$ —	$(192,634)	$ 760,013

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

Laredo Petroleum Holdings, Inc.
Consolidated statements of cash flows
For the years ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$ 105,554	$ 86,248	$(184,495)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income tax expense (benefit)	59,374	(25,812)	(74,006)
Depreciation, depletion and amortization	176,366	97,411	58,005
Impairment expense	243	—	246,669
Non-cash equity and stock-based compensation	6,111	1,257	1,419
Accretion of asset retirement obligations	616	475	406
Unrealized (gain) loss on derivative financial instruments, net	(20,890)	11,648	46,003
Premiums paid for derivative financial instruments	(555)	(5,397)	(6,283)
Amortization of premiums paid for derivative financial instruments	471	155	—
Bad debt expense	—	—	91
Amortization of deferred loan costs	3,871	2,132	546
Write-off of deferred loan costs	6,195	—	—
Amortization of October Notes premium	(39)	—	—
Amortization of other assets	19	19	9
Loss on disposal of assets	40	30	85
(Increase) decrease in accounts receivable	(30,196)	(23,299)	22,062
(Increase) decrease in other assets	(833)	(2,331)	6,092
Increase (decrease) in accounts payable	(3,825)	5,711	(6,753)
Increase (decrease) in undistributed revenues and royalties	16,180	735	1,905
Increase (decrease) in accrued compensation and benefits	2,492	5,621	(3,188)
Increase (decrease) in other accrued liabilities	23,031	2,457	3,781
Increase (decrease) in deferred lease liabilities	(149)	(17)	321
Net cash provided by operating activities	344,076	157,043	112,669
Cash flows from investing activities:			
Restricted cash	—	—	2,201
Capital expenditures:			
Oil and natural gas properties	(687,062)	(454,161)	(340,636)
Pipeline and gas gathering assets	(13,368)	(4,277)	(19,995)
Other fixed assets	(6,413)	(2,198)	(3,071)
Proceeds from other fixed asset disposals	56	89	168
Net cash used in investing activities	(706,787)	(460,547)	(361,333)
Cash flows from financing activities:			
Broad Oak Transaction	(81,963)	—	—
Borrowings on revolving credit facilities	790,100	250,300	114,400
Payments on revolving credit facilities	(1,096,700)	(105,800)	(15,900)
Borrowings on term loan	—	100,000	—
Payments on term loan	(100,000)	—	—
Issuance of 2019 Notes	552,000	—	—
Proceeds from initial public offering, net	319,378	—	—
Proceeds from issuance of equity interests, net	—	10,000	29,580
Purchase of equity interests and units, net	(164)	(513)	(762)
Purchase of treasury stock	(3)	—	—
Capital contributions	—	75,000	125,000
Payments for loan costs	(23,170)	(9,235)	(2,179)
Net cash provided by financing activities	359,478	319,752	250,139
Net increase (decrease) increase in cash and cash equivalents	(3,233)	16,248	1,475
Cash and cash equivalents, beginning of year	31,235	14,987	13,512
Cash and cash equivalents, end of year	$ 28,002	$ 31,235	$ 14,987
Non-cash financing activities:			
Capital contributions receivable	$ —	$ —	$ 50,000
Supplemental disclosure of cash flow information:			
Cash paid during the period:			
Interest	$ 31,157	$ 15,223	$ 7,096

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

Laredo Petroleum Holdings, Inc.

Notes to the consolidated financial statements

December 31, 2011, 2010 and 2009

A—Organization

Laredo Petroleum Holdings, Inc. ("Laredo Holdings") was incorporated pursuant to the laws of the State of Delaware on August 12, 2011 for the purposes of a Corporate Reorganization (as defined below) and the initial public offering of its common stock (the "IPO"). As a holding company, Laredo Holdings' management operations are conducted through its wholly-owned subsidiary, Laredo Petroleum, Inc. ("Laredo"), a Delaware corporation, and Laredo's subsidiaries, Laredo Petroleum Texas, LLC ("Laredo Texas"), a Texas limited liability company, Laredo Gas Services, LLC ("Laredo Gas"), a Delaware limited liability company, and Laredo Petroleum—Dallas, Inc. ("Laredo Dallas"), a Delaware corporation.

Laredo was incorporated on October 10, 2006, for the purpose of acquiring, developing and operating oil and natural gas producing properties on its behalf and on the behalf of others. On October 20, 2006, Laredo entered into a consulting agreement with Warburg Pincus Private Equity IX, L.P. ("Warburg Pincus IX") under which Laredo, as an independent contractor, agreed to pursue and develop acquisition and investment opportunities in the oil and natural gas industry for the benefit of Warburg Pincus IX and certain of its affiliates (collectively, the "Warburg Pincus Partnerships").

In May 2007, Warburg Pincus IX and certain members of Laredo's management contributed their common stock in Laredo to Laredo Petroleum, LLC ("Laredo LLC"), a Delaware limited liability company, and Laredo became a wholly-owned subsidiary of Laredo LLC. The consulting agreement between Laredo and Warburg Pincus IX was consequently terminated. Laredo LLC was focused on the exploration, development and acquisition of oil and natural gas in the Mid-Continent and Permian regions of the United States.

Broad Oak Energy, Inc. ("Broad Oak"), a Delaware corporation, was formed on May 11, 2006, and was engaged in the acquisition, exploration, development and production of oil and natural gas in the southwestern United States. Immediately upon formation, Broad Oak entered into a stock purchase agreement with Warburg Pincus IX and Broad Oak management.

On July 1, 2011, Laredo LLC and Laredo completed the acquisition of Broad Oak, which became a wholly-owned subsidiary of Laredo. In connection with the transaction, Laredo LLC issued: (i) approximately 86.5 million preferred equity units to Warburg Pincus IX and its affiliate in exchange for the convertible preferred stock previously held in Broad Oak; and (ii) approximately 2.4 million preferred equity units to Broad Oak's management and directors in exchange for certain of the vested common stock and convertible preferred stock previously held in Broad Oak. In addition, Laredo paid approximately $82 million in cash for certain Broad Oak vested common stock, convertible preferred stock and all outstanding and vested Broad Oak options that certain Broad Oak directors, management and employees elected to sell. All unvested shares of Broad Oak common stock and unvested Broad Oak options were cancelled. Immediately following the consummation of this transaction, Laredo LLC assigned 100% of its ownership interest in Broad Oak to Laredo as a contribution to capital (the transactions described in this paragraph are collectively, the "Broad Oak Transaction"). On July 19, 2011, Broad Oak's name was changed to Laredo Petroleum—Dallas, Inc.

Laredo LLC and Broad Oak were commonly controlled by Warburg Pincus Partnerships, and as such the Broad Oak Transaction was accounted for in a manner similar to a pooling of interests. As a result, the accompanying historical financial statements give retrospective effect to the Broad Oak

A—Organization (Continued)

Transaction, whereby the assets and liabilities of Laredo LLC and its subsidiaries and Broad Oak are reflected at the historical carrying values and their operations are presented as if they were consolidated for all periods. The consolidated equity statement presents Broad Oak's historical equity as "Other equity interests," all of which was exchanged for either (i) equity in Laredo LLC through BOE Preferred Units or (ii) cash in the Broad Oak Transaction.

Prior to the IPO, Laredo LLC merged with and into Laredo Holdings on December 19, 2011, with Laredo Holdings being the surviving entity, and the three classes of preferred units of Laredo LLC, namely the (i) Series A-1, (ii) Series A-2 and (iii) BOE Preferred Units (collectively, the "Preferred Units") and certain series of restricted units of Laredo LLC were exchanged into shares of common stock of Laredo Holdings based on the pre-offering equity value of such units in a corporate reorganization (the "Corporate Reorganization"). This resulted in the Preferred Units and the restricted units being exchanged into 104,079,546 and 3,420,454 shares of common stock of Laredo Holdings, respectively, or 107,500,000 shares of common stock in the aggregate. The 107,500,000 shares of common stock included 912,137 restricted shares issued to management and employees in exchange for unvested units in the Corporate Reorganization and 7,405 treasury shares held by Laredo Holdings. The conversion of the Preferred Units and the restricted units resulted in fractional shares of Laredo Holdings issued to each respective unit holder, which aggregated to 204 shares of common stock. Laredo Holdings then purchased all fractional shares based on the offering price of $17.00 per share, these shares are held as treasury stock. After the fractional share purchase and treasury stock transaction, 106,580,353 vested shares and 912,038 unvested shares were outstanding at the completion of the Corporate Reorganization. The common stock has one vote per share and a par value of $0.01 per share.

Laredo Holdings completed the IPO of 20,125,000 of its shares of common stock on December 20, 2011, which included 2,625,000 shares of common stock issued pursuant to the over-allotment option exercised by the underwriters of the IPO. The net proceeds from the sale of 20,125,000 shares of common stock, after underwriting discounts and commissions and offering expenses, was $319.4 million.

In these notes, the "Company," when used in the present tense, prospectively or for historical periods since December 19, 2011, refers to Laredo Holdings, Laredo and its subsidiaries collectively, and for historical periods prior to December 19, 2011 refers to Laredo LLC, Laredo and its subsidiaries collectively, unless the context indicates otherwise.

B—Basis of presentation and significant accounting policies

1. Basis of presentation

The accompanying consolidated financial statements were derived from the historical accounting records of the Company and reflect the historical financial position, results of operations and cash flows for the periods described herein. As discussed in Note A, the Broad Oak Transaction was accounted for in a manner similar to a pooling of interests and the historical financial statements present the assets and liabilities of Laredo Holdings and subsidiaries and Broad Oak at historical carrying values and their operations as if they were consolidated for all periods presented. All material intercompany transactions and account balances have been eliminated in the consolidation of accounts. The accompanying consolidated financial statements have been prepared in accordance with accounting

B—Basis of presentation and significant accounting policies (Continued)

principles generally accepted in the United States of America ("GAAP"). The Company operates oil and natural gas properties as one business segment, which explores, develops and produces oil and natural gas.

2. Use of estimates in the preparation of consolidated financial statements

The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management of the Company to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Significant estimates include, but are not limited to, estimates of the Company's reserves of oil and natural gas, future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, equity and stock-based compensation, deferred income taxes and fair values of commodity and interest rate derivatives. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management's best judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment. Such estimates and assumptions are adjusted when facts and circumstances dictate. Illiquid credit markets and volatile equity and energy markets have consolidated to increase the uncertainty inherent in such estimates and assumptions. Management believes its estimates and assumptions to be reasonable under the circumstances. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in estimates resulting from future changes in the economic environment will be reflected in the financial statements in future periods.

3. Reclassifications

Certain immaterial amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2011 presentation. These reclassifications had no impact to previously reported net income or losses, total stockholders'/unit holders' equity or cash flows.

4. Cash and cash equivalents

The Company maintains cash and cash equivalents in bank deposit accounts and money market funds that may not be federally insured. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts. The Company defines cash and cash equivalents to include cash on hand, cash in bank accounts and highly liquid investments with original maturities of three months or less.

5. Accounts receivable

The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest and oil and natural gas

B—Basis of presentation and significant accounting policies (Continued)

sales receivables related to these operations are generally unsecured. Accounts receivable for joint interest billings are recorded as amounts billed to customers less an allowance for doubtful accounts. Amounts are considered past due after 30 days. The Company determines joint interest operations accounts receivable allowances based on management's assessment of the creditworthiness of the joint interest owners and the Company's ability to realize the receivables through netting of anticipated future production revenues. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging, and existing industry and national economic data. The Company reviews its allowance for doubtful accounts quarterly. Past due balances over 90 days and over a specified amount are reviewed individually for collectability. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is remote.

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

(in thousands)	2011	2010
Oil and natural gas sales	$49,434	$31,773
Joint operations(1)	24,190	12,031
Other	511	135
Total, net	$74,135	$43,939

(1) Accounts receivable for joint operations are presented net of an allowance for doubtful accounts of approximately $0.1 million at December 31, 2011 and 2010, respectively.

6. *Derivative financial instruments*

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and natural gas. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations due to fluctuations in commodity prices. These transactions are primarily in the form of swaps, basis swaps, puts and collars. In addition, the Company enters into derivative contracts in the form of interest rate derivatives to minimize the effects of fluctuations in interest rates.

Derivative instruments are recorded at fair value and are included on the consolidated balance sheets as assets or liabilities. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists. The Company determines the fair value of its derivative financial instruments utilizing pricing models for significantly similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties.

The Company's derivatives at December 31, 2011, 2010 or 2009 were not designated as hedges for financial statement purposes. Accordingly, the changes in fair value are recognized in the consolidated statement of operations in the period of change. Realized and unrealized gains and losses on derivatives are included in cash flows from operating activities (see Note G).

B—Basis of presentation and significant accounting policies (Continued)

7. Other current assets and liabilities

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

(in thousands)	2011	2010
Prepaid expenses	$2,131	$1,483
Materials and supplies	187	4,154
Total other current assets	$2,318	$5,637

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

(in thousands)	2011	2010
Lease operating expense accrual	$ 5,297	$ 2,913
Prepaid drilling liability	2,378	1,896
Production taxes payable	1,493	1,378
Current portion of asset retirement obligations	506	731
Other accrued liabilities	5,245	3,125
Total other current liabilities	$14,919	$10,043

8. Materials and supplies

Materials and supplies, which are included in current assets and other assets, are comprised of equipment used in developing oil and natural gas properties. They are carried at the lower of cost or market using the average cost method. On a regular basis, the Company reviews quantities of materials and supplies on hand and records a provision for excess or obsolete materials and supplies, if necessary.

During the year ended December 31, 2011, the Company reduced materials and supplies by approximately $0.2 million in order to reflect the balance at the lower of cost or market. Although management believes it has established adequate allowances, it is possible that additional losses on materials and supplies could occur in future periods. The Company determined a lower of cost or market adjustment was not necessary for materials and supplies at December 31, 2010.

9. Oil and natural gas properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of finding oil and natural gas are capitalized and amortized on a composite units of production method based on proved oil and natural gas reserves. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Costs, including related employee costs, associated with production and general corporate activities are expensed in the period incurred. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of

B—Basis of presentation and significant accounting policies (Continued)

capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

The Company computes the provision for depletion of oil and natural gas properties using the units of production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. Approximately $117.2 million and $96.5 million of such costs were excluded from the amortization base at December 31, 2011 and 2010, respectively. The amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Total accumulated depletion for oil and natural gas properties was $884.5 million and $713.1 million for the years ended December 31, 2011 and 2010, respectively. Depletion expense for oil and natural gas properties was $171.5 million, $93.8 million and $55.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. Impairment expense was $245.9 million for the year ended December 31, 2009. There were no impairments recorded for years ended December 31, 2011 and 2010. Depletion per barrel of oil equivalent for the Company's oil and natural gas properties was $19.82, $18.00 and $15.54 for the years ended December 31, 2011, 2010 and 2009, respectively.

The Company excludes the costs directly associated with acquisition and evaluation of unproved properties from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. These properties are assessed at least quarterly to ascertain whether impairment has occurred. Such costs are transferred into the amortization base on an ongoing basis as projects are evaluated and proved reserves established or impairment is determined.

The Company assesses all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

The full cost ceiling is based principally on the estimated future net cash flows from oil and natural gas properties discounted at 10%. Full cost companies are required to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices were defined by contractual arrangements, to calculate the discounted future revenues. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the Securities and Exchange Commission ("SEC"), the excess is charged to expense in the period during which such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

At December 31, 2011, the full cost ceiling value of the Company's reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2011 of $3.99 per MMBtu for natural gas, adjusted by area for energy content, transportation fees, and regional price differentials by area, and the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2011 of $92.71 per barrel for oil,

B—Basis of presentation and significant accounting policies (Continued)

adjusted by area for energy content, transportation fees, and regional price differentials by area. Using these prices, the Company's net book value of oil and natural gas properties did not exceed the full cost ceiling amount at December 31, 2011. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company's actual full cost ceiling test calculation and impairment analyses in future periods.

At December 31, 2010, the full cost ceiling value of the Company's reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2010 of $4.15 per MMBtu for natural gas, adjusted by area for energy content, transportation fees, and regional price differentials by area, and the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2010 of $75.96 per barrel for oil, adjusted by area for energy content, transportation fees, and regional price differentials by area. Using these prices, the Company's net book value of oil and natural gas properties did not exceed the full cost ceiling amount at December 31, 2010.

At December 31, 2009, the full cost ceiling value of the Company's reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period ended December 31, 2009 price of $3.15 per MMBtu for natural gas, adjusted by lease for energy content, transportation fees, and regional price differentials, on the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period ended December 31, 2009 price of $57.04 per barrel for oil, adjusted by lease for quality, transportation fees, and regional price differentials. Using these prices, the Company's net book value of oil and natural gas properties at December 31, 2009, exceeded the full cost ceiling amount. As a result, the Company recorded a non-cash full cost ceiling impairment of $245.9 million before income taxes and $159.8 million after taxes.

10. Pipeline and gas gathering assets

Pipeline and gas gathering assets are recorded at cost, net of accumulated depletion, depreciation and amortization ("DD&A"), and consist of gathering assets and related equipment. Depreciation of assets is provided using the shorter of the lease term or the straight-line method based on estimated useful lives of twenty years, as applicable. Expenditures for major renewals or betterments, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation and amortization are removed from the accounts and any gain or loss is recognized in "Non-operating income (expense)" in the consolidated statements of operations. DD&A expense for pipeline and gathering assets was $2.5 million, $2.0 million and $1.5 million for the years ended December 31, 2011, 2010 and 2009, respectively. Pipeline and gathering assets consist of the following as of December 31:

(in thousands)	2011	2010
Pipeline and gas gathering assets	$58,136	$43,271
Less accumulated depreciation and amortization	6,394	3,928
Total, net	$51,742	$39,343

B—Basis of presentation and significant accounting policies (Continued)

11. Other fixed assets

Other fixed assets are recorded at cost net of accumulated depreciation and amortization and consist of furniture and fixtures, vehicles, leasehold improvements and computer hardware and software. Depreciation of other fixed assets is provided using the shorter of the lease term or the straight-line method based on estimated useful lives of three to ten years, as applicable. Leasehold improvements are capitalized and amortized over the shorter of the estimated useful lives of the assets or the terms of the related leases. Expenditures for major renewals or betterments, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation and amortization are removed from the accounts and any gain or loss is recognized in "Non-operating income (expense)" in the consolidated statements of operations. DD&A expense for other fixed assets was $2.4 million, $1.6 million and $1.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Other property and equipment fixed assets consist of the following as of December 31:

(in thousands)	2011	2010
Computer hardware and software	$ 6,206	$ 4,677
Leasehold improvements	1,847	1,781
Drilling service assets	5,742	1,985
Vehicles	1,279	1,022
Furniture and fixtures	1,021	673
Production equipment	255	219
Other	598	512
	16,948	10,869
Less accumulated depreciation and amortization	5,858	3,601
Total, net	$11,090	$ 7,268

12. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no materially significant liabilities of this nature existed at December 31, 2011 or 2010.

B—Basis of presentation and significant accounting policies (Continued)

13. Deferred loan costs

Loan origination fees are stated at cost, net of amortization, which are amortized over the life of the respective debt agreements on a basis that represents the effective interest method. The Company capitalized $23.2 million and $10.1 million of deferred loan costs in 2011 and 2010, respectively. The Company had total deferred loan costs of $23.5 million and $10.4 million, net of accumulated amortization of $4.4 million and $2.8 million, as of December 31, 2011 and 2010, respectively.

During the year ended December 31, 2011, the Company wrote-off $6.2 million in deferred loan costs as a result of the early retirement of the Term Loan (as defined below), the early retirement of the Broad Oak Credit Facility (as defined below) and changes in the borrowing base under the $1.0 billion revolving Senior Secured Credit Facility (as defined below).

Future amortization expense of deferred loan costs at December 31, 2011 is as follows:

(in thousands)	
2012	$ 4,240
2013	4,240
2014	4,240
2015	4,240
2016	2,993
Thereafter	3,504
Total	$23,457

14. Other assets and other noncurrent liabilities

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

(in thousands)	2011	2010
Materials and supplies	$5,797	$1,886
Other assets, net	65	85
Total other assets	$5,862	$1,971

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

(in thousands)	2011	2010
Gas imbalances	$ 935	$1,093
Deferred lease liability	399	591
Total other noncurrent liabilities	$1,334	$1,684

15. Asset retirement obligations

Asset retirement obligations associated with the retirement of tangible long-lived assets, are recognized as a liability in the period in which they are incurred and become determinable. The

B—Basis of presentation and significant accounting policies (Continued)

associated asset retirement costs are part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related long-lived asset is charged to expense through the depletion of the asset. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and as corresponding accretion expense. See Note H for fair value disclosures related to the Company's asset retirement obligations.

The Company is obligated by contractual and regulatory requirements to remove certain pipeline and gas gathering assets and perform other remediation of the sites where such pipeline and gas gathering assets are located upon the retirement of those assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. The Company will record an asset retirement obligation for pipeline and gas gathering assets in the periods in which settlement dates are reasonably determinable.

The following reconciles the Company's asset retirement obligations liability as of December 31:

(in thousands)	2011	2010
Liability at beginning of year	$ 8,278	$ 5,845
Liabilities added due to acquisitions, drilling, and other	1,519	1,291
Liabilities removed due to sale of wells	—	(34)
Accretion expense	616	475
Liabilities settled upon plugging and abandonment	(340)	(1,250)
Revision of estimates	3,001	1,951
Liability at end of year	$13,074	$ 8,278

16. Fair value measurements

The carrying amounts reported in the consolidated balance sheets for cash and cash equivalents, accounts receivable, prepaid expenses, accounts payable, undistributed revenue and royalties, and other accrued liabilities approximate their fair values. See Note C for fair value disclosures related to the Company's debt obligations. The Company carries its derivative financial instruments at fair value. See Note G and Note H for details about the fair value of the Company's derivative financial instruments.

17. Treasury stock

The Company accounts for treasury stock at cost. See Note A for discussion of the Company's treasury stock transactions.

18. Revenue recognition

Oil and natural gas revenues are recorded using the sales method. Under this method, the Company recognizes revenues based on actual volumes of oil and natural gas sold to purchasers. The Company and other joint interest owners may sell more or less than their entitlement share of the volumes produced. Under the sales method, when a working interest owner has overproduced in excess of its share of remaining estimated reserves, the overproduced party recognizes the excessive gas imbalance as a liability. If the underproduced working interest owner determines that an overproduced

B—Basis of presentation and significant accounting policies (Continued)

partner's share of remaining net reserves is insufficient to settle the imbalance, the underproduced owner recognizes a receivable, net of any allowance from the overproduced working interest owner.

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

(dollars in thousands)	2011	2010
Natural gas imbalance current receivable (included in "Accounts receivable—Oil and natural gas sales")	$ 22	$ 174
Underproduced positions (Mcf)	6,312	43,720
Natural gas imbalance current liability (included in "Other current liabilities")	$ 32	$ 15
Overproduced positions (Mcf)	9,049	3,839
Natural gas imbalance long-term liability (included in "Other noncurrent liabilities")	$ 935	$ 1,093
Overproduced positions (Mcf)	264,808	275,201

	For the years ended December 31,		
(dollars in thousands)	2011	2010	2009
Value of net (overproduced) underproduced positions arising during the period increasing oil and natural gas sales	$ (10)	$ 25	$ (311)
Net overproduced (underproduced) positions arising during the period (Mcf)	32,353	(12,772)	63,229

19. General and administrative expense

The Company receives fees for the operation of jointly-owned oil and natural gas properties and records such reimbursements as a reduction of general and administrative expenses.

The following amounts have been recorded for the years ended December 31, 2011, 2010 and 2009:

	For the years ended December 31,		
(in thousands)	2011	2010	2009
Fees received for the operation of jointly-owned oil and natural gas properties	$2,241	$1,497	$1,273

20. Equity and stock-based awards

Prior to the Corporate Reorganization on December 19, 2011, the Company recognized equity-based awards as a charge against earnings over the requisite service period, in an amount equal to the fair value of equity-based awards granted to employees and directors. The fair value of the equity-based awards was computed at the date of grant. Refer to Note E and Note O for further information regarding the Company's equity-based awards/stock-based awards.

For stock-based compensation equity awards, compensation expense is recognized in the Company's financial statements over the awards' vesting periods based on their grant date fair value. The Company utilizes the closing stock price on the date of grant to determine the fair value of service vesting restricted stock awards.

B—Basis of presentation and significant accounting policies (Continued)

21. Income taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carry-forwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. Additionally, the Company has not recorded any reserves for uncertain tax positions. See Note F for detail of amounts recorded in the consolidated financial statements.

22. Impairment of long-lived assets

Impairment losses are recorded on property and equipment used in operations and other long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. See Note B.8 for disclosure of the 2011 write-down of materials and supplies and Note B.9 for disclosure of the 2009 non-cash full cost ceiling impairment. Other than the aforementioned write-downs, for the years ended December 31, 2011, 2010 and 2009, the Company did not record any additional impairment to property and equipment used in operations or other long-lived assets.

23. Related party transactions

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

	For the years ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Net oil and natural gas sales(1)	$79,300	$35,000	$7,288

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

	At December 31,	
(in thousands)	**2011**	**2010**
Oil and natural gas sales receivable(1)	$6,845	$4,435

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

C—Debt

1. Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2011, 2010 and 2009:

(in thousands)	For the years ended December 31, 2011	2010	2009
Cash payments for interest	$31,157	$15,223	$7,096
Amortization of deferred loan costs and other adjustments	4,231	2,256	493
Accrued interest related to the October Notes(1)	(3,378)	—	—
Change in accrued interest	18,570	1,003	(125)
Total interest expense	$50,580	$18,482	$7,464

(1) As part of the October 19, 2011 offering of $200 million additional senior unsecured notes (further explained below), Laredo received $3.4 million in interest from the initial notes purchasers, which represents the interest on such notes that accrued from August 15, 2011 to October 19, 2011, the date of the issuance of the notes. This accrued interest was paid to the holders of such notes by Laredo on February 15, 2012.

The following table presents the weighted average interest rates and the weighted average outstanding debt balances for the years ended December 31, 2011, 2010 and 2009:

	Years ended December 31,					
	2011		2010		2009	
(in thousands except for percentages)	Weighted Average Principal	Weighted Average Interest Rate	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%	$154,011	3.67%
2019 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%	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 conjunction with the Broad Oak Transaction.

2. 2019 Notes

On January 20, 2011, Laredo completed an offering of $350 million 9½% Senior Notes due 2019 (the "January Notes"). The January Notes will mature on February 15, 2019 and bear an interest rate of 9.5% per annum payable semi-annually, in cash, in arrears on February 15 and August 15 of each year, commencing August 15, 2011. The January Notes are fully and unconditionally guaranteed, jointly

C—Debt (Continued)

and severally, on a senior unsecured basis by Laredo Holdings and (other than Laredo) its subsidiaries (collectively, the "Guarantors"). The net proceeds from the January Notes were used (i) to repay and retire $100 million outstanding under Laredo's Second Lien Term Loan Agreement (the "Term Loan"), (ii) to pay in full $177.5 million outstanding under Laredo's revolving Second Amended and Restated Senior Secured Credit Facility Agreement (the "Senior Secured Credit Facility"), and (iii) for general working capital purposes.

On October 19, 2011 Laredo completed an offering of an additional $200 million 9½% Senior Notes due 2019 (the "October Notes" and together with the January Notes, the "2019 Notes"), at a price of 101% of par. The October Notes were issued under the same Indenture (defined below) as the January Notes and are part of the same series as the January Notes. As such, the October Notes will mature on February 15, 2019 and bear an interest rate of 9.5% per annum payable semi-annually, in cash, in arrears on February 15 and August 15 of each year, commencing February 15, 2012. Interest accrued on the October Notes beginning August 15, 2011. The October Notes are fully and unconditionally guaranteed, jointly and severally on a senior unsecured basis by the Guarantors. The net proceeds from the October Notes were used to pay down $200 million of the loan amounts outstanding under the Senior Secured Credit Facility. At December 31, 2011, the carrying amount of the October Notes was approximately $202.0 million which includes a bond premium of approximately $2.0 million. The bond premium is being amortized into interest expense over the life of the 2019 Notes on a basis that represents the effective interest method.

The 2019 Notes were issued under and are governed by an indenture dated January 20, 2011 (as supplemented, the "Indenture") among Laredo, Wells Fargo Bank, National Association, as trustee, and the Guarantors. The Indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of dividends or similar restricted payments, the undertaking of transactions with Laredo's unrestricted affiliates and limitations on asset sales. Indebtedness under the 2019 Notes may be accelerated in certain circumstances upon an event of default as set forth in the Indenture.

Laredo will have the option to redeem the 2019 Notes, in whole or in part, at any time on or after February 15, 2015, 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, to the date of redemption. In addition, before February 15, 2015, Laredo may redeem all or any part of the 2019 Notes at a redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. Furthermore, before February 15, 2014, Laredo may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the 2019 Notes with the net proceeds of a public or private equity offering at a redemption price of 109.500% of the principal amount of 2019 Notes, plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the 2019 Notes issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. Laredo may also be required to make an offer to purchase the 2019 Notes upon a change of control triggering event.

C—Debt (Continued)

In connection with the issuance of the 2019 Notes, (i) Laredo and the Guarantors party thereto entered into a registration rights agreement with the initial purchasers of the January Notes on January 20, 2011 and (ii) Laredo and the Guarantors party thereto entered into a registration rights agreement with the initial purchasers of the October Notes on October 19, 2011 pursuant to which, in each case, Laredo and the Guarantors agreed to file with the SEC and use commercially reasonable efforts to cause to become effective a registration statement with respect to an offer to exchange the 2019 Notes for substantially identical notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) registered under the Securities Act of 1933, as amended (the "Securities Act"), so as to permit the exchange offer to be consummated by the 365th day after January 20, 2011. The offer to exchange the 2019 Notes for substantially identical notes registered under the Securities Act was consummated on January 13, 2012.

3. Senior secured credit facility

As previously described in Note A, on July 1, 2011, Laredo LLC and Laredo consummated a transaction by which Broad Oak became a wholly-owned subsidiary of Laredo. The cash portion of the transaction was funded under an amendment and restatement to the Senior Secured Credit Facility. Under this third amendment and restatement, the Senior Secured Credit Facility's capacity increased to $1.0 billion, with a borrowing base of $712.5 million, at December 31, 2011. At December 31, 2011, $85.0 million was outstanding. The borrowing base is subject to a semi-annual redetermination based on the financial institutions' evaluation of the Company's oil and natural gas reserves. The amendment lengthened the term of the Senior Secured Credit Facility, making it available to July 1, 2016, at which time the outstanding balance will be due. As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an Adjusted Base Rate plus applicable margin and (ii) the Eurodollar advances under the facility bear interest, at our election, at the end of one-month, two-month, three-month, six-month or, to the extent available, twelve-month interest periods (and in the case of six-month and twelve-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, based on the ratio of outstanding revolving credit to the conforming base rate. Laredo is also required to pay an annual commitment fee on the unused portion of the bank's commitment of 0.375% to 0.5%.

The Senior Secured Credit Facility is secured by a first priority lien on Laredo and the Guarantor's assets and stock, including oil and natural gas properties, constituting at least 80% of the present value of the Company's proved reserves. Further, the Company is subject to various financial and non-financial ratios on a consolidated basis, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Senior Secured Credit Facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with derivative positions. Additionally, at the end of each calendar quarter, the Company must maintain a ratio of its consolidated net income (a) plus each of the following; (i) any provision for (or less any benefit from) income or franchise taxes; (ii) consolidated net interest expense; (iii) depreciation, depletion and amortization expense; (iv) exploration expenses; and (v) other noncash charges, and (b) minus all non-cash income ("EBITDAX"), as defined in the Senior Secured Credit Facility, to the sum of net interest expense plus letter of credit fees of not less than 2.50 to 1.00, in each case for the four quarters then ending. The

C—Debt (Continued)

Senior Secured Credit Facility contains both financial and non-financial covenants and the Company was in compliance with these covenants at December 31, 2011 and 2010.

Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $20.0 million. At December 31, 2011, Laredo had one letter of credit outstanding totaling $0.03 million under the Senior Secured Credit Facility.

4. Retirement of term loan

In January 2011, Laredo paid in full its $100.0 million outstanding balance under the Term Loan, dated July 7, 2010, between Laredo and certain financial institutions, using a portion of the proceeds from its January Notes and retired the loan. The Term Loan was subject to an interest rate of 9.25% prior to its pay-off and subsequent retirement.

5. Retirement of Broad Oak credit facility

At July 1, 2011, Broad Oak had a $600.0 million revolving credit facility under its Seventh Amendment to the Credit Agreement (the "Broad Oak Credit Facility"), dated April 11, 2008, between Broad Oak and certain financial institutions. As of June 30, 2011, the Broad Oak Credit Facility had a borrowing base of $375 million with $265.4 million outstanding. As of December 31, 2010, the borrowing was $250 million with $214.1 million outstanding. The borrowing base was subject to a semi-annual redetermination based on the financial institutions' evaluation of Broad Oak's oil and natural gas reserves. The Broad Oak Credit Facility was available to Broad Oak until April 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 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. Broad Oak was also required to pay a quarterly commitment fee of 0.5% on the unused portion of the bank's commitment.

The Broad Oak Credit Facility was secured by a first priority lien on Broad Oak's oil and natural gas properties. Further, Broad Oak was subject to various financial and non-financial ratios, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Broad Oak Credit Facility, the current ratio represented the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with non-cash derivative positions. Additionally, at the end of each calendar quarter, Broad Oak had to maintain a ratio of debt to "Consolidated EBITDAX" of not more than 3.50 to 1.00, based on the quarter then ended annualized. "Consolidated EBITDAX" is defined as consolidated net income plus the sum of (i) income or franchise taxes; (ii) consolidated net interest expense; (iii) depreciation, depletion and amortization expense; (iv) any non-cash losses or charges on any derivative positions; (v) other noncash charges; and (vi) costs associated with oil and natural gas capital expenditures that are expensed rather than capitalized, less, to the extent included in the calculation of Consolidated Net Income (as defined in the Broad Oak Credit Facility), the sum of (A) the income of any person (other than wholly owned subsidiaries of such person) unless such income is received by such person in a cash distribution; (B) gains for losses from sales or other dispositions of assets (other than hydrocarbons produced in the normal course of business); (C) any non-cash gains on any hedge agreement resulting from the requirements of Accounting Standards Codification 815, *Derivatives and Hedging,* for that period;

C—Debt (Continued)

(D) extraordinary or non-recurring gains, but not net of extraordinary or non-recurring "cash" losses; and (E) costs and expenses associated with, and attributable to, oil and natural gas capital expenditures that are expensed rather than capitalized. The Broad Oak Credit Facility contained both financial and non-financial covenants and Broad Oak was in compliance with these covenants at December 31, 2010.

Additionally, the Broad Oak Credit Facility provided for the issuance of letters of credit, limited to the total capacity. At December 31, 2010, Broad Oak had no letters of credit outstanding.

On July 1, 2011, Laredo paid the Broad Oak Credit Facility in full and the facility was terminated. Upon consummation of the acquisition of Broad Oak, Broad Oak was added as a guarantor under the Senior Secured Credit Facility and the 2019 Notes and its name was changed to Laredo Petroleum—Dallas, Inc. on July 19, 2011.

6. Fair value of debt

The following table presents the carrying amount and fair value of the Company's debt instruments at December 31, 2011 and 2010:

	December 31, 2011		December 31, 2010	
(in thousands)	Carrying value	Fair value	Carrying value	Fair value
2019 Notes(1)	$551,961	$585,750	$ —	$ —
Credit Facilities(2)	85,000	84,893	391,600	392,097
Term Loan	—	—	100,000	100,707
Total value of debt	$636,961	$670,643	$491,600	$492,804

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

(2) December 31, 2010 values include the Broad Oak Credit Facility.

At December 31, 2011 the fair value of the debt outstanding on the 2019 Notes was determined using the December 31, 2011 quoted market price. For December 31, 2011, the fair value of the outstanding debt on the Laredo Senior Secured Credit Facility and for December 31, 2010, the fair value of the outstanding debt on the Laredo Senior Secured Credit Facility, the Broad Oak Credit Facility and the Term Loan was estimated utilizing pricing models for similar instruments.

D—Owners' equity

In the Corporate Reorganization, the Series A-1 Units, Series A-2 Units, BOE Preferred Units, Series B-1 Units, Series B-2 Units, Series D Units, Series F Units, Series G Units and BOE Incentive Units of Laredo LLC were exchanged into shares of common stock of Laredo Holdings based on the pre-offering equity value of such units. This resulted in the Series A-1 Units, Series A-2 Units and BOE Preferred Units being exchanged for 32,469,452; 21,011,572; and 50,598,522 shares of Laredo Holdings common stock, respectively, and the Series B Units, Series B-2 Units, Series D Units, Series F Units, Series G Units and BOE Incentive Units being exchanged for 2,029,425; 300,269; 666,857; 303,673; 66,333; and 53,897 shares of Laredo Holdings common stock, respectively, or 107,500,000 shares of common stock in the aggregate. The shares of common stock have one vote per share and a par value of $0.01 per share. The exchange of the units had no effect on the book value of stockholders' equity/ unit holders' equity.

Preferred units

Prior to the Corporate Reorganization, the Laredo LLC Second Amended and Restated Limited Liability Company Agreement (the "LLC Agreement") provided for the issuance of three classes of preferred units, (i) Series A-1, (ii) Series A-2 and (iii) BOE Preferred Units. First, the LLC Agreement authorized a total of 60.0 million Series A-1 Units of Laredo LLC for total consideration of $300 million, consisting of approximately $294.9 million from Warburg Pincus IX and $5.1 million from certain members of Laredo LLC's management team and Board of Managers. This portion was fully funded as of December 31, 2009. Second, the LLC Agreement provided for a total of 48.0 million Series A-2 Units of Laredo LLC for total consideration of $300 million, initially consisting of approximately $288.5 million from Warburg Pincus Private Equity X O&G, L.P. ("Warburg Pincus X"), $9.2 million from Warburg Pincus X Partners, L.P. ("Warburg Pincus X Partners") and $2.3 million from certain members of Laredo LLC's management team and Board of Managers. Third, the LLC Agreement authorized a total of 89.0 million BOE Preferred Units, all of which were issued and outstanding at September 30, 2011, for total consideration of $670.1 million, consisting of approximately $611.2 million from Warburg Pincus IX, $40.6 million from WP IX Finance LP and $18.4 million from Broad Oak's management team.

The Series A-1 and A-2 Units, (collectively the "Series A Units") and the BOE Preferred Units, had a liquidation preference amount equal to the total capital then invested, plus a 7% cumulative return, compounded quarterly. The holders of the Series A Units and BOE Preferred Units received the accumulated preferred return upon the consummation of the qualified public offering, as defined in the LLC Agreement. Prior to the IPO, approximately $1,219.2 million had been contributed to Laredo LLC, net of Series A Unit repurchases by Laredo LLC. Of this total, approximately $906.0 million was contributed by Warburg Pincus IX, $238.4 million by Warburg Pincus X, $40.6 million by WP IX Finance LP, $7.6 million by Warburg Pincus X Partners, $18.4 million by the former Broad Oak management team and former directors and $8.2 million by certain members of Laredo LLC's management and Board of Managers.

Restricted units

Prior to the Corporate Reorganization, Laredo LLC was authorized to issue up to 16,923,077 Series B Units, up to 8,791,209 Series C Units, up to 13,538,462 Series D Units up to 7,032,967

D—Owners' equity (Continued)

Series E Units, up to 5,538,542 Series F Units, up to 4,299,635 Series G Units and up to 1,245,195 BOE Incentive Units under restricted unit agreements (collectively, the "Restricted Units"). The Series B Units were divided into two unit series, B-1 Units and B-2 Units. The Series B-1 Units had an initial threshold value of $0 and the Series B-2 Units had an initial threshold value of $1.25. The Series C Units had an initial threshold value of $10.00, the Series D Units, Series F Units, and Series G Units had an initial threshold value of $1.25, the Series E Units had an initial threshold value of $13.75, and the BOE Incentive Units have an initial threshold value of $0.

The table below summarizes the activity relating to the Restricted Units by series prior to the Corporate Reorganization on December 19, 2011:

(in thousands)	Series B units	Series C units	Series D units	Series E units	Series F units	Series G units	Series BOE Incentive units	Total units
BALANCE, December 31, 2008	8,757	7,780	—	—	—	—	—	16,537
Issuance of restricted units	54	—	4,644	5,996	—	—	—	10,694
Cancellation of restricted units	(113)	(100)	(49)	(10)	—	—	—	(272)
BALANCE, December 31, 2009	8,698	7,680	4,595	5,986	—	—	—	26,959
Issuance of restricted units	—	—	5,530	756	—	—	—	6,286
Cancellation of restricted units	(700)	(420)	(513)	(180)	—	—	—	(1,813)
BALANCE, December 31, 2010	7,998	7,260	9,612	6,562	—	—	—	31,432
Issuance of restricted units	—	—	2,356	170	5,370	1,197	766	9,859
Cancellation of restricted units	(376)	(370)	(275)	(120)	(18)	(140)	(90)	(1,389)
BALANCE, December 19, 2011	7,622	6,890	11,693	6,612	5,352	1,057	676	39,902

E—Equity and stock-based compensation

Restricted Stock Awards

As part of the Corporate Reorganization, vested Restricted Units were exchanged for 2,500,807 shares of common stock of Laredo Holdings and unvested Restricted Units were exchanged for 912,038 restricted stock awards of Laredo Holdings. In accordance with GAAP, it was determined that the fair value of the unit awards immediately prior to the conversion was equal to the fair value of the shares of common stock immediately after the conversion and as such, the basis in the former unvested Restricted Units was carried over to the unvested shares of common stock of Laredo Holdings. Therefore, the exchange of Restricted Units for common stock of Laredo Holdings resulted in no incremental compensation costs. The restricted stock awards are subject to the same vesting and forfeiture as the unvested Restricted Units they exchanged for.

E—Equity and stock-based compensation (Continued)

The following table reflects the outstanding restricted stock awards following the Corporate Reorganization as of December 31, 2011:

(in thousands, except for grant date fair values)	Restricted stock awards	Weighted-average grant date fair value
Outstanding at December 19, 2011	—	$ —
Exchanged	912	1.14
Vested	(1)	1.11
Outstanding at December 31, 2011	911	$1.14

In November 2011, the Board of Directors of Laredo Holdings and its stockholder approved a Long-Term Incentive Plan (the "LTIP"), which provides for the granting of incentive awards in the form of stock options, restricted stock awards and other awards. The LTIP provides for the issuance of 10.0 million shares. No awards or shares were outstanding under the LTIP as of December 31, 2011. See Note O for discussion of the February 2012 issuance of restricted stock, stock option awards and other awards.

The term "equity-based" refers to awards in the form of Restricted Units of Laredo LLC prior to December 19, 2011. The term "stock-based" refers to the unvested Restricted Units exchanged for restricted stock awards of Laredo Holdings. The Company recognizes the fair value of equity and stock-based payments to employees and directors as a charge against earnings. The Company recognizes equity and stock-based payment expense over the requisite service period. Laredo LLC's equity-based awards were and Laredo Holdings' stock-based payment awards are accounted for as equity instruments. Equity and stock-based compensation are included in "Equity and stock-based compensation" in the consolidated statements of operations.

The following table presents equity-based compensation for the year ended December 31, 2011, 2010 and 2009, respectively.

(in thousands)	For the years ended December 31, 2011	2010	2009
Equity-based compensation until December 19, 2011	$5,961	$1,257	$1,419
Stock-based compensation from December 19, 2011 to December 31, 2011	150	—	—
Total equity and stock-based compensation	$6,111	$1,257	$1,419

For the year ended December 31, 2011, the estimated market value of equity-based compensation for Restricted Units and stock-based compensation for the restricted stock awards the Restricted Units were exchanged for were estimated based on a valuation prepared by the Company's third-party valuation firm. The estimated market value was calculated at the end of each calendar quarter and the estimated market value of the Company was applied to each Series B-1, B-2, C, D, E, F, G and BOE Incentive Units granted during the current calendar quarter. The method of allocation was based on first determining the enterprise value using the market approach and the income approach and then

E—Equity and stock-based compensation (Continued)

weighting the indicated value to arrive at the fair value of the unit grants. The allocation of total equity remaining after giving effect to the preference amounts based upon the Preferred Units of the Company and the issued units' initial threshold value, as defined in the LLC Agreement was then determined by a valuation model taking into account the facts and circumstances that exist at the preceding quarter end and was allocated to each series of Restricted Units. Although the fair value of the unit grants were determined in accordance with GAAP, that value may not be indicative of the fair value observed in a market transaction between a willing buyer and a willing seller.

For the year ended December 31, 2010, the fair value of equity-based compensation for Restricted Units was estimated based on the Company's estimated market value. The Company calculated the estimated market value at the end of each calendar quarter and then applied the calculated value to each Series B-1, B-2, C, D and E Units granted during the current calendar quarter. The Company's determination of the fair value for Series B-1, B-2, C, D and E Units was calculated based on the value of the Company's proved reserves using published market prices held flat after year five and then applying the following present value factors to the cash flows for proved reserves: 8% to proved developed properties, 15% to proved developed nonproducing properties and 20% to proved undeveloped properties. The aggregate calculated values were then adjusted by the net value of the Company's other non-oil and natural gas assets and liabilities to arrive at a net asset value. The net asset value was then adjusted for equity capital invested and the corresponding 7% preference amount to arrive at our net equity value. The net value was then allocated to each class of outstanding units, based upon unit sharing ratios and unit threshold values to arrive at the fair market value for each respective award. Although the fair value of the unit grants was determined in accordance with GAAP, that value may not be indicative of the fair value observed in a market transaction between a willing buyer and a willing seller.

Prior to the Corporate Reorganization, Laredo LLC was authorized to issue equity incentive awards in the form of Restricted Units. Unvested Restricted Units could not be sold, transferred or assigned. The fair value of the Restricted Units was measured based upon the estimated market price of the underlying member units as of the date of grant. The Restricted Units were subject to the following vesting terms: 20% at the grant date and 20% annually thereafter. The fair value of the Restricted Units in excess of the amounts paid by the employee, which is zero, was amortized to expense over its applicable requisite service period using the straight-line method. In the event of a termination of employment for cause, all Restricted Units, including unvested Restricted Units and vested Restricted Units, and all rights arising from such Restricted Units and from being a holder thereof, were forfeited. In the event of a termination of employment without cause or a resignation, all unvested Restricted Units and all rights arising from such Restricted Units and from being a holder thereof, were forfeited. For a period of one year from the date of termination of employment, in the event of a termination of employment for cause, the Company could elect to redeem the Series A Units and BOE Preferred Units at a price per unit equal to the lesser of the fair market value or original purchase price. In the event of a termination without cause or a resignation, the Company could elect to redeem the Series A Units and BOE Preferred Units and vested Restricted Units at a price equal to the fair market value.

E—Equity and stock-based compensation (Continued)

The tables below summarize activity relating to the unvested Restricted Units prior to the Corporate Reorganization on December 19, 2011:

(in thousands, except grant date fair values)	Series B-1	Weighted average fair value	Series B-2	Weighted average fair value	Series C	Weighted average fair value	Series D	Weighted average fair value
Outstanding at December 31, 2008	4,221	$0.34	1,975	$2.16	5,581	$—	—	$ —
Granted	—	$ —	54	$ —	—	$—	4,644	$ —
Vested	(1,242)	$0.26	(502)	$2.12	(1,536)	$—	(930)	$ —
Forfeited	(80)	$1.75	(14)	$2.23	(80)	$—	(43)	$ —
Outstanding at December 31, 2009	2,899	$0.33	1,513	$2.10	3,965	$—	3,671	$ —
Granted	—	$ —	—	$ —	—	$—	5,530	$ —
Vested	(1,055)	$0.27	(483)	$2.12	(1,416)	$—	(1,983)	$ —
Forfeited	(425)	$0.64	(88)	$2.17	(420)	$—	(473)	$ —
Outstanding at December 31, 2010	1,419	$0.36	942	$2.10	2,129	$—	6,745	$ —
Granted	—	$ —	—	$ —	—	$—	2,256	$0.67
Vested	(1,043)	$0.24	(453)	$2.13	(1,346)	$—	(2,345)	$0.13
Forfeited	(10)	$0.35	(17)	$ —	—	$—	(78)	$0.05
Outstanding at December 19, 2011	366	$0.68	472	$2.08	783	$—	6,578	$0.18

(in thousands, except grant date fair values)	Series E	Weighted average fair value	Series F	Weighted average fair value	Series G	Weighted average fair value	BOE Incentive	Weighted average fair value
Outstanding at December 31, 2008	—	$ —	—	$ —	—	$ —	—	$ —
Granted	5,996	$ —	—	$ —	—	$ —	—	$ —
Vested	(1,199)	$ —	—	$ —	—	$ —	—	$ —
Forfeited	(8)	$ —	—	$ —	—	$ —	—	$ —
Outstanding at December 31, 2009	4,789	$ —	—	$ —	—	$ —	—	$ —
Granted	756	$ —	—	$ —	—	$ —	—	$ —
Vested	(1,349)	$ —	—	$ —	—	$ —	—	$ —
Forfeited	(180)	$ —	—	$ —	—	$ —	—	$ —
Outstanding at December 31, 2010	4,016	$ —	—	$ —	—	$ —	—	$ —
Granted	170	$0.05	5,340	$1.46	1,197	$5.12	766	$3.36
Vested	(1,322)	$ —	(1,068)	$1.34	(219)	$5.12	(140)	$3.37
Forfeited	(2)	$ —	(14)	$1.46	(140)	$5.12	(90)	$3.36
Outstanding at December 19, 2011	2,862	$ —	4,258	$1.46	838	$5.12	536	$3.37

E—Equity and stock-based compensation (Continued)

For the years ended December 31, 2011, 2010 and 2009, respectively, unrecognized equity and stock-based compensation expense related to restricted stock awards/unvested Restricted Units was $13.0 million, $2.1 million and $3.7 million. That cost is expected to be recognized over a weighted average period of 1.5 years.

A summary of weighted average grant date fair values and intrinsic values of Restricted Units that vested during the period ended December 19, 2011 (prior to the Corporate Reorganization) and the year ended December 31, 2010 are as follows:

(in thousands, except weighted average grant date fair values)	December 19, 2011	December 31, 2010
B-1 Units:		
Weighted average grant date fair value	$ 0.24	$0.27
Total intrinsic value of units vested	$2,736	$ 431
B-2 Units:		
Weighted average grant date fair value	$ 2.13	$2.12
Total intrinsic value of units vested	$ 965	$ —
C Units:		
Weighted average grant date fair value	$ —	$ —
Total intrinsic value of units vested	$ 236	$ —
D Units:		
Weighted average grant date fair value	$ 0.13	$ —
Total intrinsic value of units vested	$1,038	$ —
E Units:		
Weighted average grant date fair value	$ —	$ —
Total intrinsic value of units vested	$ 14	$ —
F Units:		
Weighted average grant date fair value	$ 1.34	$ —
Total intrinsic value of units vested	$1,558	$ —
G Units:		
Weighted average grant date fair value	$ 5.12	$ —
Total intrinsic value of units vested	$1,123	$ —
BOE Incentive Units:		
Weighted average grant date fair value	$ 3.37	$ —
Total intrinsic value of units vested	$ 472	$ —

F—Income taxes

Income taxes in these financial statements are generally presented on a "consolidated" basis. However, in light of the historic ownership structure of the Company, 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 Transaction 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.

F—Income taxes (Continued)

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

As previously discussed in Note A, Laredo LLC merged into Laredo Holdings on December 19, 2011, and accordingly Laredo Holdings will file a consolidated return for the period December 19, 2011 through December 31, 2011. Prior to the Corporate Reorganization, Laredo LLC's subsidiaries were subject to corporate income taxes. Laredo Holdings and its subsidiaries are subject to corporate income taxes. In addition, the Company is subject to the Texas margin tax. Income tax (expense) benefit for the years ended December 31, 2011, 2010 and 2009 consisted of the following:

(in thousands)	2011	2010	2009
Current taxes			
Federal	$ —	$ —	$ —
State	—	—	—
Deferred taxes			
Federal	(58,727)	27,345	69,046
State	(647)	(1,533)	4,960
Income tax (expense) benefit	$(59,374)	$25,812	$74,006

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

(in thousands)	2011	2010	2009
Income tax (expense) benefit computed by applying the statutory rate	$(56,076)	$(20,548)	$ 87,891
State income tax, net of federal tax benefit and increase in valuation allowance	(2,530)	(1,118)	3,110
Income from non-taxable entity	30	48	61
Non-deductible compensation	(2,078)	(418)	(482)
Valuation allowance	660	47,888	(16,476)
Other items	620	(40)	(98)
Income tax (expense) benefit	$(59,374)	$ 25,812	$ 74,006

F—Income taxes (Continued)

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

(in thousands)	2011	2010
Derivative financial instruments	$ 3,551	$ 10,862
Oil and natural gas properties and equipment	(87,138)	(59,854)
Net operating loss carry-forward	180,740	207,427
Other	(926)	(2,174)
	96,227	156,261
Valuation allowance	(649)	(1,309)
Net deferred tax asset	$ 95,578	$154,952

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

(in thousands)	2011	2010
Deferred tax asset	$95,578	$154,952
Deferred tax liability	—	—
Net deferred tax assets	$95,578	$154,952

The Company had federal net operating loss carry-forwards totaling approximately $511.5 million and state net operating loss carry-forwards totaling approximately $167.6 million at December 31, 2011. These carry-forwards begin expiring in 2026. The Company maintains a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. At December 31, 2011, a $0.6 million valuation allowance has been recorded against the state of Louisiana deferred tax asset and a $0.02 million valuation allowance has been recorded against the Company's charitable contribution carry-forward. The Company believes the federal and state of Oklahoma net operating loss carry-forwards are fully realizable. The Company considered all available evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance was needed. Such consideration included estimated future projected earnings based on existing reserves and projected future cash flows from its oil and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities recorded at December 31, 2011 and the Company's ability to capitalize intangible drilling costs, rather than expensing these costs, in order to prevent an operating loss carry-forward from expiring unused.

The Company's income tax returns for the years 2008 through 2010 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma, Texas and Louisiana which are the jurisdictions where the Company has or had operations. Additionally, the statute of limitations for examination of federal net operating loss carryovers typically does not begin to run until the year the attribute is utilized in a tax return. In evaluating its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy in identifying uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules, and the significance of each position. The Company had no material adjustments to its unrecognized tax benefits during the year ended December 31, 2011.

G—Derivative financial instruments

1. Commodity derivatives

The Company engages in derivative transactions such as collars, swaps, puts and basis swaps to hedge price risks due to unfavorable changes in oil and natural gas prices related to its oil and natural gas production. As of December 31, 2011, the Company had 44 open derivative contracts with financial institutions, none of which were designated as hedges, which extend from January 2012 to December 2014. The contracts are recorded at fair value on the balance sheet and any realized and unrealized gains and losses are recognized in current year earnings.

Each collar transaction has an established price floor and ceiling. When the settlement price is below the price floor established by these collars, the Company receives an amount from its counterparty equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume.

Each swap or put transaction has an established fixed price. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

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

G—Derivative financial instruments (Continued)

During the year ended December 31, 2011, the Company entered into additional commodity contracts to hedge a portion of its estimated future production. The following table summarizes information about these additional commodity derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Aggregate volumes	Swap price	Floor price	Ceiling price	Contract period
Oil (volumes in Bbls):					
Swap	100,000	$101.00	$ —	$ —	March 2011 - December 2011
Price collar	160,000	$ —	$85.00	$125.00	March 2011 - December 2011
Swap	90,000	$100.10	$ —	$ —	April 2011 - December 2011
Price collar	80,000	$ —	$95.00	$125.70	May 2011 - December 2011
Price collar	120,000	$ —	$85.00	$125.00	January 2012 - December 2012
Price collar	348,000	$ —	$75.00	$125.00	January 2012 - December 2012
Swap	120,000	$ 99.75	$ —	$ —	January 2012 - December 2012
Swap	120,000	$101.10	$ —	$ —	January 2012 - December 2012
Swap	120,000	$100.06	$ —	$ —	January 2012 - December 2012
Price collar	312,000	$ —	$75.00	$125.00	January 2013 - December 2013
Swap	120,000	$ 99.10	$ —	$ —	January 2013 - December 2013
Swap	120,000	$100.02	$ —	$ —	January 2013 - December 2013
Swap	120,000	$102.50	$ —	$ —	January 2013 - December 2013
Price collar	96,000	$ —	$85.00	$125.00	January 2013 - December 2013
Price collar	264,000	$ —	$80.00	$125.00	January 2014 - December 2014
Price collar	264,000	$ —	$75.00	$125.00	January 2014 - December 2014
Natural gas (volumes in MMBtu):					
Basis swap	500,000	$ 0.26	$ —	$ —	March 2011 - December 2011
Swap	350,000	$ 4.75	$ —	$ —	June 2011 - December 2011
Price collar	3,480,000	$ —	$ 4.00	$ 7.05	January 2014 - December 2014
Price collar	3,480,000	$ —	$ 4.00	$ 7.00	January 2014 - December 2014

G—Derivative financial instruments (Continued)

The following table summarizes open positions as of December 31, 2011, and represents, as of such date, derivatives in place through December 31, 2014, on annual production volumes:

	Year 2012	Year 2013	Year 2014
Oil Positions:			
Puts:			
Hedged volume (Bbls)	672,000	1,080,000	—
Weighted average price ($/Bbl)	$ 65.79	$ 65.00	$ —
Swaps:			
Hedged volume (Bbls)	732,000	600,000	—
Weighted average price ($/Bbl)	$ 93.52	$ 96.32	$ —
Collars:			
Hedged volume (Bbls)	846,000	528,000	528,000
Weighted average floor price ($/Bbl)	$ 75.04	$ 74.55	$ 77.50
Weighted average ceiling price ($/Bbl)	$ 114.50	$ 123.18	$ 125.00
Natural Gas Positions:			
Puts:			
Hedged volume (MMBtu)	4,320,000	6,600,000	—
Weighted average price ($/MMBtu)	$ 5.38	$ 4.00	$ —
Swaps:			
Hedged volume (MMBtu)	1,680,000	—	—
Weighted average price ($/MMBtu)	$ 6.14	$ —	$ —
Collars:			
Hedged volume (MMBtu)	7,800,000	6,600,000	6,960,000
Weighted average floor price ($/MMBtu)	$ 4.12	$ 4.00	$ 4.00
Weighted average ceiling price ($/MMBtu)	$ 5.79	$ 7.05	$ 7.03
Basis swaps:			
Hedged volume (MMBtu)	2,880,000	1,200,000	—
Weighted average price ($/MMBtu)	$ 0.31	$ 0.33	$ —

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

2. Interest rate derivatives

The Company is exposed to market risk for changes in interest rates related to its Senior Secured Credit Facility. Interest rate derivative agreements are used to manage a portion of the exposure related to changing interest rates by converting floating-rate debt to fixed-rate debt. If LIBOR is lower than the fixed rate in the contract, the Company is required to pay the counterparties the difference, and conversely, the counterparties are required to pay the Company if LIBOR is higher than the fixed rate in the contract. For the interest rate cap below, the Company paid a premium of $0.2 million in

G—Derivative financial instruments (Continued)

2010 upon entering into the agreement. The Company did not designate the interest rate derivatives as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings.

The following presents the settlement terms of the interest rate derivatives at December 31, 2011:

(in thousands except rate data)	Year 2012	Year 2013
Notional amount	$110,000	—
Fixed rate	3.41%	—
Notional amount	$ 30,000	—
Fixed rate	1.60%	—
Notional amount	$ 20,000	—
Fixed rate	1.35%	—
Notional amount	$ 50,000	$ 50,000
Fixed rate	1.11%	1.11%
Notional amount	$ 50,000	$ 50,000
Cap rate	3.00%	3.00%
Total	$260,000	$100,000

3. Balance sheet presentation

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

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

	December 31,	
(in thousands)	2011	2010
Assets:		
Commodity derivatives:		
Oil derivatives	$16,026	$ 8,398
Natural gas derivatives	34,019	22,035
Interest rate derivatives	11	248
	$50,056	$30,681
Liabilities:		
Commodity derivatives:		
Oil derivatives(1)	$28,044	$23,405
Natural gas derivatives(2)	6,832	9,271
Interest rate derivatives	1,991	5,790
	$36,867	$38,466

(1) The oil derivatives fair value is presented net of deferred premium liability of $13.4 million and $7.6 million at December 31, 2011 and 2010, respectively.

G—Derivative financial instruments (Continued)

(2) The natural gas derivatives fair value is presented net of deferred premium liability of $5.4 million and $4.9 million at December 31, 2011 and 2010, respectively.

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are participants in its Senior Secured Credit Facility (as described in Note C) which is secured by the Company's oil and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not require collateral from its counterparties. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that are also lenders in the Company's Senior Secured Credit Facility and meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets the Company's minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity and interest rate derivatives are subject to counterparty netting under agreements governing such derivatives and, therefore, the risk of such loss is somewhat mitigated at December 31, 2011.

4. Gain (loss) on derivatives

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

The following represents the Company's reported gains and losses on derivative instruments for the years ended December 31, 2011, 2010 and 2009:

(in thousands)	Years ended December 31, 2011	2010	2009
Realized gains (losses):			
Commodity derivatives	$ 3,719	$ 22,701	$ 52,117
Interest rate derivatives	(4,873)	(5,238)	(3,764)
	(1,154)	17,463	48,353
Unrealized gains (losses):			
Commodity derivatives	17,328	(11,511)	(46,373)
Interest rate derivatives	3,562	(137)	370
	20,890	(11,648)	(46,003)
Total gains (losses):			
Commodity derivatives	21,047	11,190	5,744
Interest rate derivatives	(1,311)	(5,375)	(3,394)
	$19,736	$ 5,815	$ 2,350

H—Fair value measurements

The Company accounts for its oil and natural gas commodity and interest rate derivatives at fair value (see Note G). The fair value of derivative financial instruments is determined utilizing pricing models for similar instruments. The models use a variety of techniques to arrive at fair value, including quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward curves generated from a compilation of data gathered from third parties.

The Company has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities recorded at fair value on the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

Level 1—Assets and liabilities recorded at fair value for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2—Assets and liabilities recorded at fair value for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the price risk management instrument, can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3—Assets and liabilities recorded at fair value for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. Unobservable inputs that are not corroborated by market data. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on an annual basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities.

Fair value measurement on a recurring basis

The following presents the Company's fair value hierarchy for assets and liabilities measured at fair value on a recurring basis at December 31, 2011 and 2010. These items are included in "Derivative financial instruments" on the consolidated balance sheets. Significant Level 2 assumptions associated with the calculation of discounted cash flows used in the "mark-to-market" analysis include the

H—Fair value measurements (Continued)

NYMEX natural gas and crude oil prices, appropriate risk adjusted discount rates and other relevant data.

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

(in thousands)	Level 1	Level 2	Level 3	Total fair value
As of December 31, 2010:				
Commodity derivatives	$—	$ (9,774)	$ 20,026	$ 10,252
Deferred premiums	—	—	(12,495)	(12,495)
Interest rate derivatives	—	(5,542)	—	(5,542)
Total	$—	$(15,316)	$ 7,531	$ (7,785)

A summary of the changes in assets classified as Level 3 measurements for the years ended December 31, 2011 and 2010 are as follows:

(in thousands)	Derivative option contracts	Deferred premiums
Balance of Level 3 at December 31, 2010	$ 20,026	$(12,495)
Realized and unrealized gains included in earnings	5,323	—
Amortization of deferred premiums	—	(471)
Total purchases and settlements:		
Purchases	—	(5,988)
Settlements	—	86
Transfers out of Level 3(1)(2)	(25,349)	—
Balance of Level 3 at December 31, 2011	$ —	$(18,868)
Change in unrealized losses attributed to earnings relating to derivatives still held at December 31, 2010	$ —	$ —

H—Fair value measurements (Continued)

(in thousands)	Derivative option contracts	Deferred premiums
Balance of Level 3 at December 31, 2009	$14,610	$ (3,524)
Realized and unrealized losses included in earnings	(1,965)	—
Amortization of deferred premiums	—	(116)
Total purchases and settlements:		
Purchases	7,381	(8,855)
Settlements	—	—
Balance of Level 3 at December 31, 2010	$20,026	$(12,495)
Change in unrealized gains attributed to earnings relating to derivatives still held at December 31, 2010	$ 2,392	$ —

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

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

Fair value measurement on a nonrecurring basis

The Company accounts for additions to its asset retirement obligation (see Note B.15) and impairment of long-lived assets (see Note B.22), if any, at fair value on a nonrecurring basis in accordance with GAAP. For purposes of fair value measurement, it was determined that the impairment of long-lived assets and the additions to the asset retirement obligation are classified as Level 3 based on the use of internally developed cash flow models. No impairments of long-lived assets were recorded in 2011.

Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement, and changes in legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment will be made to the asset balance.

Asset retirement obligations. The accounting policies for asset retirement obligations are discussed in Note B.15, including a reconciliation of the Company's asset retirement obligation. The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, which converts future cash flows to a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well based on Company experience; (ii) estimated remaining life per well based on the reserve life per well; (iii) future inflation factors; and (iv) the Company's average credit adjusted risk free rate.

H—Fair value measurements (Continued)

Impairment of oil and natural gas properties. The accounting policies for impairment of oil and natural gas properties are discussed in Note B.9. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of proved reserves and other relevant data.

I—Credit risk

The Company's oil and natural gas sales are to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. The Company's joint operations accounts receivable are from a number of oil and natural gas companies, partnerships, individuals and others who own interests in the properties operated by the Company. Management believes that any credit risk imposed by a concentration in the oil and natural gas industry is offset by the creditworthiness of the Company's customer base and industry partners. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability.

The Company uses derivative instruments to hedge its exposure to oil and natural gas price volatility and its exposure to interest rate risk associated with the credit facilities (as described in Note C). These transactions expose the Company to potential credit risk from its counterparties. In accordance with the Company's standard practice, its derivative instruments are subject to counterparty netting under agreements governing such derivatives and therefore, the credit risk associated with its derivative counterparties is somewhat mitigated. See Note G for additional information regarding the Company's derivative instruments.

For the year ended December 31, 2011, the Company had three customers that accounted for 36.1%, 16.2% and 12.9% of total revenues, with the same three customers accounting for 31.6%, 13.9% and 15.9% and another customer accounting for 11.0% of oil and natural gas sales accounts receivable as of December 31, 2011. For the year ended December 31, 2010, the Company had three customers that accounted for 33.1%, 19.0%, and 14.5% of total revenues, with the same three customers accounting for 41.3%, 16.2%, and 14.0% of oil and natural gas sales accounts receivable as of December 31, 2010. For the year ended December 31, 2009, the Company had three customers that accounted for 35.8%, 13.7% and 11.7% of total revenues, with two of these customers accounting for 42.7% and 16.9% of oil and natural gas sales accounts receivable as of December 31, 2009.

For the year ended December 31, 2011, three partners' joint operations accounts receivable accounted for 30.4%, 17.4% and 16.1% of the Company's total joint operations accounts receivable. For the year ended December 31, 2010, two partners' joint operations accounts receivable accounted for 76.5% and 11.4% of the Company's total joint operations accounts receivable.

The Company's cash balances are insured by the FDIC up to $250,000 per bank. The Company had a cash balance on deposit with a certain bank in the credit facilities bank group at December 31, 2011, which exceeded the balance insured by the FDIC in the amount of $54.7 million. Management believes that the risk of loss is mitigated by the bank's reputation and financial position.

J—Commitments and contingencies

1. Lease commitments

The Company leases equipment and office space under operating leases expiring on various dates through 2016. Minimum annual lease commitments at December 31, 2011, and for the calendar years following are:

(in thousands)	
2012	$1,413
2013	1,448
2014	1,102
2015	731
2016	282
Total	$4,976

The following table presents rent expense for the years ended December 31, 2011, 2010 and 2009, respectively.

	For the years ended December 31,		
(in thousands)	2011	2010	2009
Rent expense	$1,175	$946	$822

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

2. Litigation

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

3. Drilling contracts

The Company has committed to several short-term drilling contracts with various third parties in order to complete its various drilling projects. The contracts contain an early termination clause that requires the Company to pay significant penalties to the third party should the Company cease drilling efforts. These penalties could significantly impact the Company's financial statements upon contract termination. These commitments are not recorded in the accompanying consolidated balance sheets. Future commitments as of December 31, 2011 are $9.6 million. As a result of these commitments $1.6 million in stacked rig fees were incurred in 2009. No stacked rig fees were incurred in 2011 or 2010. Management does not anticipate canceling any drilling contracts or discontinuing drilling efforts in 2012.

J—Commitments and contingencies (Continued)

4. Federal and state regulations

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

K—Defined contribution plans

Laredo sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at the date of hire. As part of the Broad Oak Transaction, Laredo began funding the former Broad Oak sponsored plan on July, 1, 2011. The former Broad Oak plan is substantially identical to the Laredo sponsored plan. The plans allow eligible employees to make tax-deferred contributions up to 100% of their annual compensation, not to exceed annual limits established by the federal government. Laredo makes matching contributions of up to 6% of an employee's compensation and may make additional discretionary contributions for eligible employees. Employees are 100% vested in the employer contributions upon receipt. The two plans merged on January 1, 2012.

The following table presents total contributions to the plans for the years ended December 31, 2011, 2010 and 2009.

(in thousands)	2011	2010	2009
Contributions	$1,651	$1,201	$1,099

L—Pro forma income per share

Pro forma weighted average shares outstanding used in the computation of pro forma basic and diluted income per share attributable to shareholders has been computed taking into account (1) the conversion ratio at the time of the Corporate Reorganization of all Preferred Units and certain Restricted Units into shares of Laredo Holdings common stock as if the conversion occurred as of the beginning of the year and (2) the 20,125,000 shares of common stock issued by the Company in the IPO.

Basic net income per share is computed by dividing net income by the pro forma weighted-average number of shares outstanding for the period. Diluted net income per share reflects the potential

L—Pro forma income per share (Continued)

dilution of non-vested restricted stock awards. The following is the calculation of basic and diluted weighted average shares outstanding and net income per share for the year ended December 31, 2011:

(in thousands, except for per share data)	Year ended December 31, 2011
Income (numerator):	
Net income—basic and diluted	$105,554
Pro forma weighted average shares (denominator):	
Pro forma weighted average shares—basic	107,187
Non-vested restricted stock	912
Pro forma weighted average shares—diluted	108,099
Pro forma net income per share:	
Basic	$ 0.98
Diluted	$ 0.98

M—Recently issued accounting standards

In May 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,* which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and International Financial Reporting Standards. This new guidance changes some fair value measurement principles and disclosure requirements, but does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. The update is effective for annual periods beginning after December 15, 2011 and the Company does not expect the adoption of this ASU to have a material effect on the consolidated financial statements.

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

N—Subsidiary guarantees

Pursuant to the terms of the Corporate Reorganization that was completed on December 19, 2011, immediately prior to the closing of the IPO, Laredo LLC was merged with and into Laredo Holdings, with Laredo Holdings surviving the merger. Laredo Holdings and all of Laredo's wholly-owned subsidiaries (Laredo Gas, Laredo Texas and Laredo Dallas, collectively, the "Subsidiary Guarantors") have fully and unconditionally guaranteed the 2019 Notes and the Senior Secured Credit Facility (see Note C). In accordance with practices accepted by the SEC, Laredo has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. The following condensed consolidating balance sheets as of December 31, 2011 and 2010, and condensed consolidating statements of operations and condensed

N—Subsidiary guarantees (Continued)

consolidating statements of cash flows each for the years ended December 31, 2011, 2010 and 2009, present financial information for Laredo Holdings or Laredo LLC, as applicable, as the parent of Laredo on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for Laredo on a stand-alone basis (carrying any investment in subsidiaries under the equity method), financial information for the Subsidiary Guarantors on a stand-alone basis (carrying any investment in subsidiaries under the equity method), and the consolidation and elimination entries necessary to arrive at the information for the Company on a condensed consolidated basis. All deferred income taxes are recorded on Laredo's statements of financial position, as Laredo's subsidiaries are flow-through entities for income tax purposes. Prior to the Broad Oak Transaction on July 1, 2011, both Laredo and Laredo Dallas were separate taxable entities and deferred income taxes for the Company are recorded separately. The Subsidiary Guarantors are not restricted from making distributions to Laredo.

Condensed consolidating balance sheet
December 31, 2011

(in thousands)	Laredo Holdings	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable	$ —	$ 53,006	$ 21,129	$ —	$ 74,135
Other current assets	54,921	20,599	204	(26,921)	48,803
Total oil and natural gas properties, net	—	780,152	535,525	—	1,315,677
Total pipeline and gas gathering assets, net	—	—	51,742	—	51,742
Total other fixed assets, net	—	10,321	769	—	11,090
Investment in subsidiaries	888,043	554,901	—	(1,442,944)	—
Total other long-term assets	—	126,205	—	—	126,205
Total assets	$942,964	$1,545,184	$609,369	$(1,469,865)	$1,627,652
Accounts payable	$ 1	$ 58,729	$ 14,198	$ (26,921)	$ 46,007
Other current liabilities	—	130,990	37,364	—	168,354
Other long-term liabilities	—	8,779	7,538	—	16,317
Long-term debt	—	636,961	—	—	636,961
Owners' equity	942,963	709,725	550,269	(1,442,944)	760,013
Total liabilities and owners' equity	$942,964	$1,545,184	$609,369	$(1,469,865)	$1,627,652

N—Subsidiary guarantees (Continued)

Condensed consolidating balance sheet
December 31, 2010

(in thousands)	Laredo LLC	Laredo	Subsidiary Guarantors	Intercompany eliminations	Total
Accounts receivable, net	$ —	$ 24,168	$ 19,771	$ —	$ 43,939
Other current assets	38,652	21,391	10,340	(13,906)	56,477
Total oil and natural gas properties, net	—	430,242	333,040	—	763,282
Total pipeline and gas gathering assets, net	—	—	39,343	—	39,343
Total other fixed assets, net	—	6,915	353	—	7,268
Investment in subsidiaries	511,208	114,881	—	(626,089)	—
Total other long-term assets	—	129,799	28,052	—	157,851
Total assets	$549,860	$727,396	$430,899	$(639,995)	$1,068,160
Accounts payable	$ 1	$ 42,311	$ 12,932	$ (13,906)	$ 41,338
Other current liabilities	—	64,675	44,230	—	108,905
Other long-term liabilities	—	6,602	8,616	—	15,218
Long-term debt	—	277,500	214,100	—	491,600
Owner's equity	549,859	336,308	151,021	(626,089)	411,099
Total liabilities and owners' equity	$549,860	$727,396	$430,899	$(639,995)	$1,068,160

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

(in thousands)	Laredo Holdings	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$—	$237,194	$280,349	$(7,273)	$510,270
Total operating costs and expenses	8	173,638	141,998	(7,273)	308,371
Income (loss) from operations	(8)	63,556	138,351	—	201,899
Interest income (expense), net	96	(45,470)	(5,098)	—	(50,472)
Other, net	—	10,492	3,009	—	13,501
Income from operations before income tax	88	28,578	136,262	—	164,928
Income tax expense	—	(37,974)	(21,400)	—	(59,374)
Net income (loss)	$88	$ (9,396)	$114,862	$ —	$105,554

N—Subsidiary guarantees (Continued)

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

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

Condensed consolidating statement of operations
For the year ended December 31, 2009

(in thousands)	Laredo LLC	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total operating revenues	$ —	$ 60,684	$ 38,956	$(3,066)	$ 96,574
Total operating costs and expenses	7	244,252	108,910	(3,066)	350,103
Loss from operations	(7)	(183,568)	(69,954)	—	(253,529)
Interest income (expense), net	185	(6,032)	(1,394)	—	(7,241)
Other, net	—	8,316	(6,047)	—	2,269
Income (loss) from operations before income tax	178	(181,284)	(77,395)	—	(258,501)
Income tax benefit	—	74,006	—	—	74,006
Net income (loss)	$178	$(107,278)	$ (77,395)	$ —	$(184,495)

N—Subsidiary guarantees (Continued)

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

(in thousands)	Laredo Holdings	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$ 89	$ 150,002	$ 207,000	$(13,015)	$ 344,076
Net cash flows provided by (used in) investing activities	(303,194)	(408,412)	4,819	—	(706,787)
Net cash flows provided by (used in) financing activities	319,374	258,410	(218,306)	—	359,478
Net increase (decrease) in cash and cash equivalents	16,269	—	(6,487)	(13,015)	(3,233)
Cash and cash equivalents at beginning of period	38,652	—	6,489	(13,906)	31,235
Cash and cash equivalents at end of period	$ 54,921	$ —	$ 2	$(26,921)	$ 28,002

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

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

N—Subsidiary guarantees (Continued)

Condensed consolidating statement of cash flows
For the year ended December 31, 2009

(in thousands)	Laredo LLC	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash flows provided by operating activities	$ 178	$ 88,896	$ 22,094	$ 1,501	$ 112,669
Net cash flows used in investing activities	(122,701)	(162,704)	(75,928)	—	(361,333)
Net cash flows provided by financing activities	124,700	73,808	51,631	—	250,139
Net increase (decrease) in cash and cash equivalents	2,177	—	(2,203)	1,501	1,475
Cash and cash equivalents at beginning of period	14,745	—	3,969	(5,202)	13,512
Cash and cash equivalents at end of period	$ 16,922	$ —	$ 1,766	$(3,701)	$ 14,987

O—Subsequent events

1. Additional borrowing

On January 9, February 9 and March 5, 2012, the Company borrowed $40.0 million, $55.0 million and $50.0 million, respectively, under the Senior Secured Credit Facility. The outstanding balance under the Senior Secured Credit Facility was approximately $230.0 million at March 19, 2012.

2. New derivative contracts

Subsequent to December 31, 2011, the Company entered into the following new commodity contracts, with approximately $1.3 million in deferred premiums associated:

	Aggregate volumes	Swap price	Floor price	Ceiling price	Contract period
Oil (volumes in Bbls):					
Price collar	270,000	—	$90.00	$126.50	April 2012 - December 2012
Price collar	240,000	—	$90.00	$118.35	January 2013 - December 2013
Price collar	198,000	—	$70.00	$140.00	January 2014 - December 2014
Price collar	252,000	—	$75.00	$135.00	January 2015 - December 2015
Natural gas (volumes in MMBtu):					
Swap	700,000	$2.72	—	—	April 2012 - October 2012
Price collar	700,000	—	$ 3.25	$ 3.90	April 2013 - October 2013

O—Subsequent events (Continued)

3. Restricted stock awards and other compensation

On February 3, 2012, the Company granted 593,939 restricted stock awards with service vesting criteria, 602,948 stock options with service vesting criteria and 49,244 performance awards with a combination of market and service vesting criteria under the LTIP and related award agreements. For stock-based compensation equity awards, compensation expense will be recognized in the Company's financial statements over the awards' vesting periods based on their grant date fair value. The Company will utilize (i) the closing stock price on the date of grant of $24.11 to determine the fair value of service vesting restricted stock awards and options and (ii) a probability analysis to determine the fair value of performance awards with a combination of market and service vesting criteria.

In accordance with the LTIP and restricted stock agreement, the restricted stock awards are subject to a three year vesting schedule, with one third vesting each year. Upon termination with or without cause all unvested shares granted and all rights arising from such shares are forfeited. In the event of the death or disability of the holder, all unvested awards shall automatically become vested.

In accordance with the LTIP and stock option agreement, the options granted will become exercisable in accordance with the following schedule based upon the number of full years of the optionee's continuous employment or service with the Company, following February 3, 2012:

Full years of continuous employment	Incremental percentage of option exercisable	Cumulative percentage of option exercisable
Less than one	0%	0%
One	25%	25%
Two	25%	50%
Three	25%	75%
Four	25%	100%

No shares of common stock may be purchased unless the optionee has remained in the continuous employment of the Company through February 2, 2013. Unless sooner terminated, the option will expire if and to the extent it is not exercised within ten years from the grant date. The unvested portion of an option will expire upon termination of employment of the optionee, and the vested portion of such option will remain exercisable for (A) one year following termination of employment by death, but not later than the option expiration or (B) 90 days following termination of employment or service with cause, but not later than the expiration of the option period. The unvested and the unexercised vested portion of the option will expire upon termination of employment for cause.

In accordance with the LTIP and the performance compensation award agreement, the performance awards have a value of $100.00. The performance units will be payable, if at all, in cash, based upon the achievement by the Company of certain performance goals, over a three year period. In the event of termination with or without cause, the performance awards are forfeited. In the event of the grantee's death or disability, the grantee is eligible for a pro-rated award.

P—Supplemental oil and natural gas disclosures

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

Costs incurred in the acquisition and development of oil and natural gas assets are presented below for the years ended December 31:

(in thousands)	2011	2010	2009
Property acquisition costs:			
Proved	$ —	$ —	$ —
Unproved	—	—	—
Exploration	62,888	87,576	53,708
Development costs	660,922	414,870	273,856
Total costs incurred	$723,810	$502,446	$327,564

2. Capitalized oil and natural gas costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are presented below as of December 31:

(in thousands)	2011	2010	2009
Capitalized costs:			
Proved properties	$2,083,015	$1,379,885	$881,106
Unproved properties	117,195	96,515	92,847
	2,200,210	1,476,400	973,953
Less accumulated depreciation, depletion, amortization and impairment	884,533	713,118	620,537
Net capitalized costs	$1,315,677	$ 763,282	$353,416

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2011, by year in which such costs were incurred:

(in thousands)	2011	2010	2009	2008 and prior	Total
Unproved properties	$67,641	$24,099	$5,772	$19,683	$117,195

Unproved properties, which are not subject to amortization, are not individually significant and consist primarily of lease acquisition costs. The evaluation process associated with these properties has not been completed and therefore, the Company is unable to estimate when these costs will be included in the amortization calculation.

P—Supplemental oil and natural gas disclosures (Continued)

3. Results of oil and natural gas producing activities

The results of operations of oil and natural gas producing activities (excluding corporate overhead and interest costs) are presented below as of December 31:

(in thousands)	2011	2010	2009
Revenues:			
Oil and natural gas sales	$506,255	$239,783	$ 94,347
Production costs:			
Lease operating expenses	43,306	21,684	12,531
Production and ad valorem taxes	31,982	15,699	6,129
	75,288	37,383	18,660
Other costs:			
Depreciation, depletion, amortization and impairment	171,517	93,815	301,279
Accretion of asset retirement obligation	616	475	406
Income tax expense (benefit)	93,180	39,223	(67,637)
Results of operations	$165,654	$ 68,887	$(158,361)

4. Net proved oil and natural gas reserves—(unaudited)

Ryder Scott Company, L.P., our independent reserve engineers ("Ryder Scott"), 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 combined 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. In accordance with SEC regulations, reserves at December 31, 2011, 2010 and 2009 were estimated using the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Our reserves are reported in two streams; crude oil and natural gas. The economic value of the natural gas liquids in our natural gas is included in the wellhead natural gas price. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, the estimates may change as future information becomes available.

P—Supplemental oil and natural gas disclosures (Continued)

An analysis of the change in estimated quantities of oil and natural gas reserves, all of which are located within the United States, for the years ended December 31, is as follows:

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

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

P—Supplemental oil and natural gas disclosures (Continued)

	Year ended December 31, 2009		
	Gas (MMcf)	Oil (MBbls)	MBOE
Proved developed and undeveloped reserves:			
Beginning of year	244,051	3,508	44,183
Revisions of previous estimates	(51,823)	(785)	(9,423)
Extensions, discoveries and other additions	105,623	3,718	21,322
Purchases of minerals in place	—	—	—
Production	(18,302)	(513)	(3,563)
End of year	279,549	5,928	52,519
Proved developed reserves:			
Beginning of year	107,175	1,506	19,368
End of year	135,204	2,905	25,439
Proved undeveloped reserves:			
Beginning of year	136,876	2,002	24,815
End of year	144,345	3,023	27,080

The tables above include changes in estimated quantities of oil and natural gas reserves shown in MBbl equivalents ("MBOE") calculated using a conversion rate of six MMcf per one MBbl.

For the year ended December 31, 2011, the Company's negative revision of 9,006 MBOE of previous estimated quantities is primarily due to the removing of uneconomic proved undeveloped locations, due to increased capital cost. Extensions, discoveries and other additions of 37,553 MBOE during the year ended December 31, 2011, consist of 14,709 MBOE primarily from the drilling of new wells during the year and 22,844 MBOE from new proved undeveloped locations added during the year, which increased the Company's proved reserves. The latter consists of 15,009 MBOE attributable to 155 locations in our Permian Basin play and 7,835 MBOE attributable to 47 locations in our Anadarko Granite Wash play. The oil and natural gas reference prices used in computing our reserves as of December 31, 2011 were $92.71 per barrel and $3.99 per MMBtu before price differentials.

For the year ended December 31, 2010, the Company's negative revision of 2,110 MBOE of previous estimated quantities is primarily due to uneconomic proved undeveloped locations. Extensions, discoveries and other additions of 91,363 MBOE during the year ended December 31, 2010, consist of 20,533 MBOE primarily from the drilling of new wells during the year and 70,830 MBOE from new proved undeveloped locations added during the year, which increased the Company's proved reserves, the latter of which consists of 63,444 MBOE attributable to 957 vertical locations in our Permian Basin play, 7,002 MBOE attributable to 53 vertical locations in our Anadarko Granite Wash play and 384 MBOE attributable to 8 locations in other areas. The oil and natural gas reference prices used in computing our reserves as of December 31, 2010 were $75.96 per barrel and $4.15 per MMBtu before price differentials.

For the year ended December 31, 2009, the Company's negative revision of previous estimated quantities is composed of a 7,708 MBOE revision due to the decrease in oil and natural gas prices at December 31, 2009 and a decrease of 1,715 MBOE for performance revisions. Extensions, discoveries and other additions of 21,322 MBOE during the year ended December 31, 2009, consist of 8,866 MBOE

P—Supplemental oil and natural gas disclosures (Continued)

primarily from the drilling of new wells during the year and 12,456 MBOE from new proved undeveloped locations added during the year, which increased the Company's proved reserves. The oil and natural gas reference prices used in computing our reserves as of December 31, 2009 were $57.04 per barrel and $3.15 per MMBtu before price differentials.

5. Standardized measure of discounted future net cash flows—(unaudited)

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties, and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2011, 2010 and 2009 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. Future income tax expenses are computed using the appropriate year-end statutory tax rates applied to the future pretax net cash flows from proved oil and natural gas reserves, less the tax basis of the Company's and Broad Oak's oil and natural gas properties. Reference prices used, before differentials were applied were $3.99, $4.15, and $3.15 per MMBtu and $92.71, $75.96 and $57.04 per Bbl of oil for December 31, 2011, 2010 and 2009, respectively. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows at December 31:

(in thousands)	2011	2010	2009
Future cash inflows	$ 8,856,906	$ 6,597,739	$1,369,593
Future production costs	(2,562,237)	(2,057,681)	(431,240)
Future development costs	(1,959,818)	(1,715,836)	(318,074)
Future income tax expenses	(999,185)	(602,551)	—
Future net cash flows	3,335,666	2,221,671	620,279
10% discount for estimated timing of cash flows	(1,934,807)	(1,351,689)	(352,664)
Standardized measure of discounted future net cash flows	$ 1,400,859	$ 869,982	$ 267,615

In the foregoing determination of future cash inflows, sales prices used for gas and oil for December 31, 2011, 2010 and 2009 were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year

P—Supplemental oil and natural gas disclosures (Continued)

shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

Changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows:

(in thousands)	2011	2010	2009
Standardized measure of discounted future net cash flows, beginning of year	$ 869,982	$ 267,615	$222,371
Changes in the year resulting from:			
Sales, less production costs	(430,967)	(202,400)	(75,687)
Revisions of previous quantity estimates	(70,021)	(15,080)	(48,209)
Extensions, discoveries and other additions	529,041	788,090	127,704
Net change in prices and production costs	566,034	214,308	(40,062)
Changes in estimated future development costs	(163,399)	(62,386)	12,062
Previously estimated development costs incurred during the period	207,818	20,082	41,620
Purchases of minerals in place	—	—	—
Accretion of discount	106,170	26,762	24,302
Net change in income taxes	(176,165)	(191,714)	20,648
Timing differences and other	(37,634)	24,705	(17,134)
Standardized measure of discounted future net cash flows, end of year	$1,400,859	$ 869,982	$267,615

Estimates of economically recoverable oil and natural gas reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are to some degree subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil and natural gas may differ materially from the amounts estimated.

Q—Supplemental quarterly financial data (unaudited)

The Company's results of operations by quarter for the years ended December 31, 2011 and 2010 are as follows:

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

	Year ended December 31, 2010			
(in thousands)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$46,993	$49,930	$60,135	$84,942
Operating income	17,390	9,640	19,379	26,573
Net income	23,923	10,602	16,633	35,090

Laredo Officers (pictured left to right) Mark Elliott, Daniel Schooley, Dave Boncaldo, Mark King, John Minton, Mark Womble, Randy Foutch, Patrick Curth, Jerry Schuyler, Rodney Myers, Jeff Tanner, Robert Skinner, and Kenneth Dornblaser. (Photo courtesy of Ben Hider/NYSE Euronext.)

Independent Directors

Peter R. Kagan
Warburg Pincus, Managing Director

James R. Levy
Warburg Pincus, Principal

B.Z. (Bill) Parker
Phillips Petroleum Company, Former Executive Vice President

Pamela S. Pierce
Ztown Investments, Inc., Partner

Ambassador Francis Rooney
Rooney Holdings, Inc. & Manhattan Construction Group, Chief Executive Officer

Edmund P. Segner, III
EOG Resources, Former President, Chief of Staff & Director

Donald D. Wolf
Quantum Resources Management, LLC, Chairman

Directors

Randy A. Foutch
Chairman & Chief Executive Officer

Jerry R. Schuyler
Director, President & Chief Operating Officer

Senior Officers

Randy A. Foutch
Chairman & Chief Executive Officer

Jerry R. Schuyler
Director, President & Chief Operating Officer

W. Mark Womble
Senior Vice President & Chief Financial Officer

Patrick J. Curth
Senior Vice President, Exploration & Land

John E. Minton
Senior Vice President, Reservoir Engineering

Rodney S. Myers
Senior Vice President, Permian

Kenneth E. Dornblaser
Senior Vice President & General Counsel

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Stock Exchange Listing

Laredo's Common Shares are publicly traded on the NYSE under the symbol "LPI."

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