
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

☒ **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**

For the transition period from _____ to _____

Commission file number: 001-35191

LONE PINE RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

27-3779606

(I.R.S. Employer
Identification No.)

Suite 1100, 640-5th Avenue SW, Calgary, Alberta Canada
(Address of principal executive offices)

T2P 3G4
(Zip Code)

Registrant's telephone number, including area code: **(403) 292-8000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class

Name of each exchange on which registered

Common Stock

New York Stock Exchange
Toronto 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 Web site, 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.

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 aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter, was US\$159,300,000 (based on the closing price of such stock).

There were 85,026,202 shares of the registrant's common stock, par value US\$0.01 per share, outstanding as of March 20, 2012.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant's notice of annual meeting of stockholders and proxy statement to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year ended December 31, 2011 are incorporated by reference into Part III of this Form 10-K.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K (this “Form 10-K”) may constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. The words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “should,” “would,” “could” or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Known material factors that could cause our actual results to differ from those in the forward-looking statements are those described in Part I, “Item 1A. Risk Factors.”

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

MONETARY AMOUNTS AND EXCHANGE RATE DATA

In this Form 10-K, references to “dollars,” “\$” or “Cdn\$” are to Canadian dollars and references to “U.S. dollars” or “US\$” are to United States dollars. We changed our reporting currency from the U.S. dollar to the Canadian dollar effective October 1, 2011. Prior to changing our reporting currency, we obtained a no objection letter from the Securities and Exchange Commission (“SEC”). See Part I, “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Note 2 of our consolidated financial statements for more information about our change in reporting currency, including the reasons for the change, the manner in which the change has been and will be applied to recast prior period financial statements, and a discussion of the major categories of items in the balance sheet, and statements of income and cash flows, that are denominated in Canadian or U.S. dollars.

The noon-day Canadian to U.S. dollar exchange rates for Cdn\$1.00, as reported by the Bank of Canada, were:

	Year ended December 31,			
	2011	2010	2009	2008
	US\$	US\$	US\$	US\$
Highest rate during the period	1.0583	1.0054	0.9715	1.0289
Lowest rate during the period	0.9430	0.9278	0.7692	0.7711
Average noon spot rate during the period(1)	1.0117	0.9709	0.8757	0.9381
Rate at the end of the period	0.9833	1.0054	0.9555	0.8166

(1) Determined by averaging the rates on each business day during the respective period.

On March 20, 2012, the noon-day exchange rate was US\$1.0067 for Cdn\$1.00.

PART I

Item 1. Business.

In this Form 10-K, unless otherwise indicated or the context otherwise requires, references to “we,” “us,” “our,” “our company,” “the Company” or “Lone Pine” when used in reference to periods prior to June 1, 2011 refer to Lone Pine Resources Canada Ltd. and its consolidated subsidiary, and when used in reference to periods after June 1, 2011, refer to Lone Pine Resources Inc., a Delaware corporation, and its consolidated subsidiaries, including Lone Pine Resources Canada Ltd. Unless the context otherwise requires, references in this Form 10-K to “LPR Canada” or “our predecessor” refer to Lone Pine Resources Canada Ltd., formerly Canadian Forest Oil Ltd., an Alberta corporation and a wholly-owned subsidiary of Lone Pine Resources Inc., which was the predecessor of Lone Pine Resources Inc., and its consolidated subsidiary. Certain oil and gas industry terms used in this Form 10-K are defined in the “—Glossary of Oil and Gas Terms” below.

Overview

We are an independent oil and gas exploration, development and production company with operations in Canada. Our reserves, producing properties and exploration prospects are located in the provinces of Alberta, British Columbia and Quebec and the Northwest Territories. We were incorporated under the laws of the State of Delaware on September 30, 2010, and prior to our initial public offering (“IPO”) on June 1, 2011, we were a wholly-owned subsidiary of Forest Oil Corporation (“Forest”). Our predecessor, Lone Pine Resources Canada Ltd., was acquired by Forest in 1996 and transferred to us prior to completion of our IPO. On September 30, 2011, Forest distributed all of the outstanding shares of our common stock that it owned to its shareholders (the “Distribution”). As a result of the Distribution, Forest has no remaining ownership interest in us.

DeGolyer and MacNaughton, our independent reserves engineers, estimated our proved reserves to be approximately 401 Bcfe as of December 31, 2011, of which approximately 26% was oil and natural gas liquids (“NGLs”), approximately 74% was natural gas and approximately 53% was classified as proved developed reserves. As of December 31, 2011, we had approximately 151 gross (125 net) proved undeveloped drilling locations and approximately 1.1 million gross (0.8 million net) acres of

land (approximately 79% of which was undeveloped). The following table presents summary data for each of our significant properties as of December 31, 2011:

	Estimated Proved Reserves (Bcfe)(1)	Estimated Proved Reserves (Bcfe)(1)	Average Daily Net Sales Volumes (MMcfe/ d)(1)(2)	Acreage		Proved Undeveloped Drilling Locations	
	Net	Net	Net	Gross	Net	Gross	Net
Evi	94	40	14.1	64,320	57,382	84	77
Other oil	11	10	3.5	19,551	17,840	1	1
Total oil	105	51	17.6	83,871	75,222	85	78
Narraway/Ojay	195	85	42.5	180,344	121,088	32	25
Wild River	67	51	19.7	26,400	12,853	26	17
Other Deep Basin	21	16	6.0	46,614	23,838	4	2
Total Deep Basin	283	152	68.2	253,358	157,779	62	44
Utica Shale(3)	—	—	—	398,850	240,320	—	—
Liard Basin	—	—	—	53,788	52,995	—	—
Total shales	—	—	—	452,638	293,315	—	—
Other	13	11	8.2	342,610	268,219	4	4
Total	401	214	94.0	1,132,477	794,535	151	125

- (1) Reserves and sales volumes are presented on a gas-equivalent basis using a conversion of six Mcf “equivalent” per barrel of oil or NGL. This conversion is based on energy equivalence and not price equivalence. For 2011, the average of the first-day-of-the-month index gas price was US\$4.15 per MMBtu for NYMEX Henry Hub (\$3.77 per MMBtu at AECO), and the average of the first-day-of-the-month index oil price was US\$96.13 per barrel for NYMEX West Texas Intermediate (“WTI”) (\$96.98 per barrel for Edmonton Light). If a price equivalent conversion based on these 12-month average prices was used, the conversion factor would be approximately 23 Mcf per barrel of oil or NGL rather than six Mcf per barrel of oil or NGL.
- (2) For the year ended December 31, 2011. Our average daily net sales volumes for the three months ended December 31, 2011 were 98.8 MMcfe/d.
- (3) On June 13, 2011, legislation was implemented in Quebec that prohibits oil and gas activities in the St. Lawrence River upstream of Anticosti Island and on the islands situated in that part of the river and revokes, without compensation, oil and gas rights previously issued for that area. We held exploration licenses to 33,460 net acres under the St. Lawrence River that were revoked by this legislation and are considering available alternatives with respect to the government’s action. The revoked acreage consists entirely of undeveloped lands.

Our History

During the past five years, we have primarily focused on the development of our Deep Basin and Evi areas, which were acquired in connection with Forest’s acquisition of The Wiser Oil Company (“Wiser”) in 2004. More recently, we have applied our experience from the Wild River field to the development and expansion of our Narraway/Ojay fields and furthered the development of our light oil assets in the Evi area.

Beginning in 2009, we applied multi-zone slick-water fracture completion technology to our Narraway/Ojay fields that yielded improved results. As a result, we undertook a significant leasing campaign in the Narraway/Ojay area and completed an acquisition in April 2011 of approximately 35,700 net acres in the Narraway field, which increased our acreage position from approximately 21,000 net acres at December 31, 2008 to approximately 121,088 net acres at December 31, 2011. We also increased our oil drilling activity in our Evi area in 2009, accelerating our horizontal drilling program that began in 2006. From 2006 through December 31, 2011, we have drilled a total of 72 gross

horizontal oil wells in the Evi area. Due to the success of our initial horizontal wells, we undertook a significant leasing campaign in the Evi area, which increased our net acreage position from approximately 11,000 net acres at December 31, 2004 to approximately 57,382 net acres at December 31, 2011.

Through our leasing efforts in Quebec, which began in 2007, we have acquired approximately 240,320 net acres in the Utica Shale play as of December 31, 2011. From 2007 through 2010, we participated in the drilling of ten exploration wells. We intend to continue to evaluate our acreage for future development while working with the Quebec Oil & Gas Association and provincial government agencies as the province undertakes a strategic environmental assessment (“SEA”) of shale gas drilling in the province as recommended by the province’s environmental public hearing board, the *Bureau d’audienees publiques sur l’environnement* (“BAPE”).

In addition to our large shale gas position in Quebec, as of December 31, 2011, we had approximately 52,995 contiguous net acres in the Liard Basin, located in the Northwest Territories, that are prospective for the Muskwa Shale. We believe that our acreage in the Liard Basin is analogous to the Muskwa Shale in the Horn River Basin.

As we have expanded into new plays, we also have divested assets that did not meet our development growth strategy. Starting in the fourth quarter of 2009 and through December 31, 2011, we divested approximately \$159 million of certain non-core or non-operated oil and gas properties, primarily in December 2009 and April 2010, that, at the time the divestitures occurred, had a combined net production rate of 16 MMcfe/d.

Our Business Strategy

Our business strategy is to increase stockholder value by efficiently increasing production, reserves and cash flow by applying horizontal drilling and new completion technologies to our significant and diversified undeveloped acreage positions. We expect to execute this strategy while managing our debt levels relative to our estimated proved reserves and cash flow. We endeavor to execute this strategy as follows:

- ***Exploit and develop resource plays by applying horizontal drilling and new completion technologies.*** We intend to apply the latest exploitation technologies to our resource plays, including horizontal drilling and multi-stage hydraulic fracture stimulation techniques. Each of our Evi and Deep Basin areas has a large number of remaining drilling locations where delineation drilling has established the existence of a consistent geologic trend, creating what we believe are repeatable development opportunities through horizontal and vertical drilling.
- ***Enhance returns by focusing on operational control and cost efficiencies.*** We plan to develop and execute large-scale, repeatable drilling programs in areas where we have high working interests, concentrated land positions, large drilling inventories and operational control to reduce costs and achieve economies of scale, thereby attaining higher rates of return on invested capital.
- ***Maintain a diversified commodity mix.*** Our current asset base is composed of both light oil and natural gas opportunities. Our diversified portfolio allows us to focus on one commodity over another when disparity between commodity prices dictates. In 2011, we were able to successfully increase our average liquids production weighting from 14% in the first quarter to 27% in the fourth quarter by focusing our capital investment on light oil. In 2012, we again plan to focus our capital budget on light oil by allocating approximately 80% of our total budget to light oil opportunities. Based on this focus, we expect to increase our average liquids production weighting from 21% in 2011 to 35% in 2012 and to approximately 40% by the end of 2012. We plan on continuing a diversified approach over the long term, with the majority of our capital allocated in the short term to assets with the highest rates of return.

- ***Develop, expand and rationalize our asset base through leasehold and property acquisitions, divestitures and exploration.*** We intend to pursue leasehold and property acquisitions to enhance existing business operations in our core areas and to gain entrance into new, complementary resource plays, with a preference for liquids-rich hydrocarbon prospects. We also plan to pursue a measured exploration drilling program in these areas in order to expand the ultimate scope of commercial development of our asset base. As economic conditions permit, we intend to divest assets that do not fit our primary business strategy, including those without significant development opportunities.
- ***Maintain financial flexibility.*** We plan to maintain a strong liquidity position to successfully execute our growth strategy through the application of budget controls and disciplined financial management. We intend to focus on managing our debt levels relative to our estimated proved reserves and cash flow. We intend to also support our future cash flow through the management of a measured commodity hedging program.

Our Competitive Strengths

We believe we have a number of competitive strengths that will help us to execute our business strategy:

- ***Large, contiguous acreage positions, with multi-year, diversified drilling inventory.*** Our leasing efforts, which have included early identification and leasehold acquisitions of acreage in prospective areas, have enabled us to develop large, contiguous acreage positions. In total, we have accumulated approximately 1.1 million gross (0.8 million net) acres in prospective areas, with approximately 79% of the acreage classified as undeveloped as of December 31, 2011. We have a commodity-diverse drilling portfolio with approximately 84 gross (77 net) proved undeveloped drilling locations as of December 31, 2011 in our Evi area targeting premium-priced light oil, and approximately 62 gross (44 net) proved undeveloped drilling locations as of December 31, 2011 in the Deep Basin targeting natural gas and NGLs. Our acreage positions allow us to be more competitive in our development efforts through the execution of large-scale drilling and multi-stage hydraulic fracture stimulation programs and the establishment of centralized gathering systems and associated facilities.
- ***Established light oil resource with future development upside.*** The Evi area has historically been produced extensively from a deeper Granite Wash horizon with over 2,500 vertical wells drilled into the play. Since 2006, the focus in the Evi area has been on a shallower Slave Point horizon that has been exploited through horizontal drilling and multi-stage hydraulic fracture stimulation. The presence of the deeper producing horizon has provided extensive well control and formed the basis of a specific geological model that we use in the development of the area. Recent developments in the area have focused on increasing the number of hydraulic fracture stages placed into a horizontal well. In 2011, we increased the average fracture density from six stages to ten stages and realized an increase in well productivity of over 60%. We believe that further improvement in well design combined with additional downspacing across our acreage provides for extensive future development opportunities.
- ***Multi-stacked intervals in the Deep Basin, which yield low-risk incremental development opportunities.*** The Deep Basin has historically been a highly prospective area for the production of natural gas and NGLs. The Deep Basin fields produce from a minimum of ten different stacked producing intervals, many of which have not been exploited horizontally. With the advancement of drilling and completion technology, many of these intervals now have the potential to be developed with favorable economic results. We believe our interests in over 250 productive wells in the Deep Basin, completed in multiple zones, and our understanding of the geology of the basin, give us a competitive advantage in the development of these unexploited intervals. Our primary focus in the Deep Basin will be in the Narraway/Ojay and Wild River fields. We believe that the application of horizontal drilling and multi-stage fracturing technologies, while more expensive

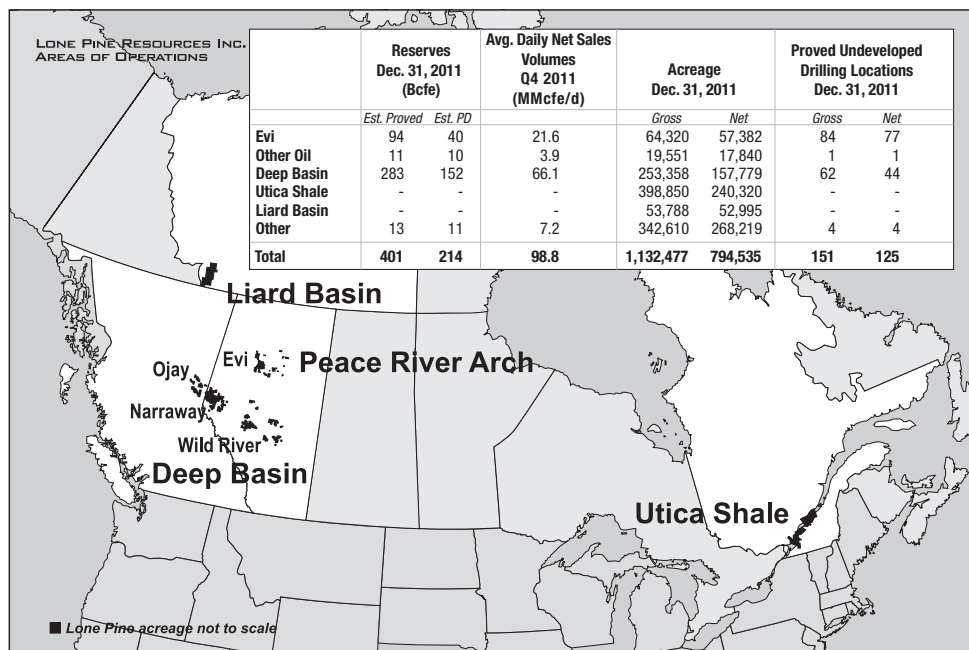
than vertical wells, will allow us to develop this and other intervals at enhanced economic rates of return.

- **Management and technical team with demonstrated operational and technical skills.** Our management and technical team has extensive expertise in the oil and gas industry. We believe that our team is one of our principal competitive strengths, as evidenced by our track record in establishing, developing and expanding our core assets with profitable rates of return. Our team has successfully implemented horizontal drilling and multi-stage hydraulic fracturing technologies and plans to expand the application of these technologies across our resource plays. From the completion of our first horizontal well in the Evi area in 2006 through December 31, 2011, we have drilled a total of 72 gross horizontal wells, improved production rates and recoveries by increasing the number of fracturing stages and reduced drilling times and drilling costs through efficiency gains. We expect to continue to pursue the application of horizontal drilling and multi-stage fracturing technologies on our extensive resource bases.
- **Operating control over a majority of our properties, with limited near-term lease expiries.** We have high working interests in our properties and currently operate over 80% of our production. Further, we operated all of our 2011 drilling program and expect to operate substantially all of our planned 2012 drilling program. As the designated operator, we believe we can maintain control over capital expenditures, operating costs and the pace of exploration and development. We also have limited near-term lease expiries. As of December 31, 2011, approximately 85% of our net acreage was held by leases whose terms extend beyond the next three years.
- **Strong balance sheet.** We have a \$500 million credit facility with a syndicate of banks led by JPMorgan Chase Bank, N.A., Toronto Branch. As of December 31, 2011, our borrowing base under the bank credit facility was \$425 million and we had approximately \$331 million in borrowings under our bank credit facility. In February 2012, our wholly-owned subsidiary, Lone Pine Resources Canada Ltd., issued US\$200 million of 10.375% Senior Notes due 2017 (the "Senior Notes"). The net proceeds of approximately \$192 million, after deduction of original issue and initial purchaser discounts and estimated offering expenses, were used to partially repay borrowings outstanding under our bank credit facility. As of March 20, 2012, we had approximately \$185 million of secured indebtedness outstanding under our bank credit facility and secured borrowing capacity of approximately \$188 million (after deducting \$1.6 million of outstanding letters of credit).
- **Strong hedging positions.** As of March 20, 2012, we had 25,000 MMBtu/d, representing approximately 40% of our forecasted 2012 average daily net natural gas production volumes hedged at an average NYMEX Henry Hub price of US\$5.09 per MMBtu/d and 3,000 bbls/d of crude oil, representing approximately 55% of our forecasted 2012 average daily net crude oil production volumes hedged at US\$102.35 (as to 2,000 bbls/d) and \$100.98 (as to 1,000 bbls/d). We also had 1,000 bbls/d of 2013 crude oil production hedged at \$102.00 (as to 500 bbls/d) and US\$101.00 (as to 500 bbls/d).

Financial Information About Segments and Geographical Areas

We operate our business as a single segment with similar economic characteristics, technology, manufacturing processes, customers, distribution and marketing strategies, regulatory environments and shared infrastructures. We operate in one industry segment, and our oil and gas exploration and production activities are exclusively within Canada. Our financial information, including our net sales and long-lived assets by geographical area, is included in our consolidated financial statements and the related notes contained elsewhere in this Form 10-K.

Significant Properties



Evi Area

As of December 31, 2011, we had approximately 57,382 net acres in and near the Evi field, located in the Peace River Arch area of northern Alberta. This position offers us a significant development opportunity for premium-priced light oil. From 2006 through December 31, 2011, we have drilled a total of 72 horizontal wells in the Evi area. We acquired our initial acreage position in the Evi field in 2004 as part of Forest's acquisition of Wiser, and we have significantly expanded our acreage position through Crown leasing and acquisitions from approximately 11,000 net acres at December 31, 2004 to 57,382 net acres at December 31, 2011. As of December 31, 2011, our acreage position in the Evi area consists of 100 gross (89 net) sections on which we have 133 gross (102 net) productive wells in the Slave Point formation, of which 72 are horizontal wells. As of December 31, 2011, we had 94 Bcfe of total estimated proved reserves at Evi, including 40 Bcfe that are classified as proved developed reserves. As of December 31, 2011, we had 84 gross (77 net) proved undeveloped drilling locations in the Evi area. Initially, we plan to drill six horizontal wells per section, although regulatory spacing in the Evi field for the Slave Point formation generally provides for eight wells per section and we have received regulatory approval to downspace certain sections in the central area of Evi to up to 16 wells per section.

In 2011, we drilled 47 gross (47 net) horizontal wells in the Evi area as compared to 25 gross (17 net) wells in 2010 and increased the number of fracture stimulation stages from an average of six to ten stages. Our working interest in all of the wells drilled in 2011 is 100%. During 2011, we had average daily net sales volumes of 2,357 bbls/d from production in the Evi area. We plan to drill up to 48 horizontal wells in the Evi area in 2012. We believe that we can ultimately enhance production rates and recoveries in the Evi area through further development drilling, including further downspacing of our acreage, completion optimization and secondary recovery techniques, such as waterflooding. We intend to continue to expand our facilities in the Evi area to accommodate the growing crude oil volumes in the area and continue to invest in our operated waterflood pilot project that we initiated in 2011. In 2012, we plan to focus our capital budget on light oil by allocating approximately 80% of our total capital budget or, approximately \$165 million, to the Evi area. Our historical costs to drill and complete horizontal wells have ranged from \$1.9 million to \$5.2 million per well and have averaged \$2.9 million per well. We expect that wells drilled in 2012 will have an average cost of \$2.9 million per well.

Deep Basin Area

As of December 31, 2011, we had approximately 157,779 net acres in the Deep Basin, including approximately 121,088 net acres in the Narraway/Ojay fields, located in Alberta and British Columbia, and approximately 12,853 net acres in the Wild River field, located in the southeast portion of the Deep Basin. In 2011, we drilled and completed 6 gross (5.5 net) wells in the Narraway/Ojay fields, including 1 gross (1 net) horizontal well. In the fourth quarter of 2011, we had average daily net sales volumes of 66 MMcfe/d from production in the Deep Basin. Our development of these assets is primarily focused on our Narraway/Ojay and Wild River fields. Geologically, these fields have a minimum of ten different stacked producing intervals, and we are able to produce from multiple intervals within an individual wellbore. We currently have no significant near-term expiries or drilling obligations in the Deep Basin, which has allowed us to be flexible with our 2012 capital budget and defer significant natural gas investment until natural gas prices improve from their existing multi-year lows. In 2012, we are allocating approximately 7% of our total capital budget, or approximately \$15 million, to the Deep Basin, where we plan to focus primarily on recompletion opportunities.

Narraway/Ojay Fields

As of December 31, 2011, we had approximately 121,088 net acres in the Narraway/Ojay fields, located in Alberta and British Columbia. This acreage position establishes us as one of the top acreage holders in the area. Following positive drilling results in the Narraway/Ojay fields during 2009, we undertook a significant leasing campaign in the Narraway/Ojay area, which increased our acreage position from approximately 21,000 net acres at December 31, 2008 to approximately 121,088 net acres at December 31, 2011. As of December 31, 2011, our land holding was 206 gross (162 net) sections, and we had 29 gross (24 net) proved undeveloped drilling locations in the Narraway field. Regulatory spacing in the Narraway field currently provides for four wells per section. Our acreage position in the Ojay field as of December 31, 2011 consisted of 56 gross (23 net) sections on which we had 9 gross (4 net) productive wells. As of December 31, 2011, we had 3 gross (1.5 net) proved undeveloped drilling locations in the Ojay field. Regulatory spacing in the Ojay field currently provides for one well per section.

From the fourth quarter of 2008 to the fourth quarter of 2011, we have increased our net sales volumes from the Narraway/Ojay fields from 5 to 44 MMcfe/d, which we believe demonstrates the significant growth potential of the Narraway/Ojay fields. Our wells in the Narraway/Ojay fields provide multi-zone completion opportunities, with the Nikanassin formation as the anchor zone, and with numerous gas bearing formations in zones above, or uphole of, the anchor zone. These uphole zones can be commingled for production purposes. The Nikanassin is the anchor formation in the fields, and we sometimes refer to the Narraway/Ojay fields as part of the Nikanassin Resource Play.

On April 29, 2011, we completed the acquisition of certain natural gas properties located in the Narraway/Ojay fields. The acquisition increased our working interests in certain properties that we already owned and operated in the Narraway field from approximately 50% to 100% and provided us with additional capacity in gathering systems and a gas plant in the Narraway field. In addition, the acquisition increased our acreage position by approximately 85,100 gross (35,700 net) acres.

Wild River Field

We have approximately 12,853 net acres in the Wild River field, located in the southeast portion of the Deep Basin. We acquired our position in 2004 as part of Forest's acquisition of Wiser. As of December 31, 2011, our acreage position in the Wild River field consisted of 41 gross (20 net) sections on which we have 156 gross (92 net) productive wells. As of December 31, 2011, we had 26 gross (17 net) proved undeveloped drilling locations in the Wild River field. Regulatory spacing in the Wild River field currently provides for eight wells per section. We have drilled 143 wells in the Wild River

field since our acquisition in 2004 through the fourth quarter of 2011. During this same period, we also reduced the average number of days to drill each well by approximately 30%. We have targeted multiple-zone intervals, with the Cadomin formation as the anchor zone. The stacked pay in our Wild River field has provided drilling opportunities that have been vertically developed; however, we believe the application of horizontal drilling and multi-stage fracturing technology, while more expensive than vertical wells, will further enhance the economic development of this field. Industry activity in the area has demonstrated horizontal success targeting the uphole, liquids-rich Cardium interval, and we believe our acreage is also prospective for this interval.

Shales

As of December 31, 2011, we had approximately 240,320 net acres in Quebec that are prospective for the Utica Shale. No reserves are attributed to our Quebec properties. Natural gas produced from this area is in close proximity to major markets in Canada and the northeastern United States, which generally provides for premium product pricing compared to the NYMEX Henry Hub pricing. The Utica Shale is relatively shallow compared to other shale plays in North America, which we believe will provide for an economic advantage relative to the drilling costs associated with developing the resource.

In 2006 and 2007, we took cores from three vertical test wells targeting a section of the upper Utica Shale, or the Upper Utica, and tested two of these wells at a peak rate of 1,000 Mcfe/d. We then drilled three horizontal test wells (each with 2,000 foot laterals and four fracture stimulation stages), which had similar initial production test rates. Our historical costs to drill and complete these horizontal wells in the Utica Shale have ranged from US\$5.8 million to US\$7.0 million. We participated in a vertical well in the area during the fourth quarter of 2010 and took samples to further confirm the rock properties associated with the Middle Utica.

Subject to minimal capital commitment, approximately 50% of our acreage is under leases that will expire in 2019, approximately 4% of our acreage is under leases that will expire in 2022 and approximately 46% of our acreage is under leases that will expire in 2023. Furthermore, transportation infrastructure is already in place in the Utica Shale, which should lower development expenditures. We believe that these factors, coupled with the area's premium natural gas prices, provide favorable development economics.

On March 8, 2011, the Government of Quebec announced that it would move forward with the SAE of shale gas drilling in the province as recommended by the BAPE, in a report delivered to the Quebec Minister of Sustainable Development, Environment and Parks. A committee was appointed in May 2011 to conduct the SEA, which is expected to take 18 to 30 months, during which the government has indicated that hydraulic fracturing will only be permitted in Quebec for scientific data gathering purposes if required for the SEA and on the committee's recommendation. The SEA committee is to report annually, with its first report due in May 2012, and ultimately propose changes to the current legislative and regulatory framework for oil and gas exploration and development in Quebec.

On June 13, 2011, in response to concerns over the impact of the SEA on the terms of existing exploration licenses, legislation was implemented to exempt holders of licenses to explore for petroleum, natural gas and underground reservoirs from prescribed exploration work requirements until a date to be determined by the government (but not later than July 13, 2014), and effectively extend the term of such licenses for the same period. The legislation also, however, prohibits oil and gas activities in the St. Lawrence River upstream of Anticosti Island and on the islands situated in that part of the river and revokes, without compensation, oil and gas rights previously issued for that area. We held exploration licenses to 33,460 net acres under the St. Lawrence River, representing approximately 14% of our overall net acres in Quebec, that were revoked by this legislation and are considering

available alternatives with respect to the government's action. The revoked acreage consists entirely of undeveloped lands. No reserves are attributed to our Quebec properties.

During the SEA period, we will be able to explore and gather scientific data on our remaining undeveloped shale acreage positions. The Ministry of Natural Resources is expected to provide interim regulations to act under during the SEA committee's undertakings. See Part I, "Item 1A. Risk Factors—Risks Related to Our Business—*New laws or regulatory requirements relating to hydraulic fracturing could make it more difficult or costly for us to perform fracturing of producing formations and could have an adverse effect on our ability to produce oil and gas from new wells*" and "—Environmental Regulation."

As of December 31, 2011, we had approximately 52,995 net acres in the Liard Basin, located in the Northwest Territories, that are prospective for the Muskwa Shale. No reserves are attributed to our Liard Basin properties. This is a newly developing natural gas shale play adjacent to the producing Horn River Basin. We believe that our acreage in the Liard Basin is analogous to the Muskwa Shale in the Horn River Basin. Our acreage is located in close proximity to a pipeline in the Northwest Territories providing for the sale and distribution of any natural gas produced. In the third and fourth quarters of 2011, we re-entered and recompleted a well in the Liard Basin, and in February 2012, we submitted an application to the National Energy Board to potentially continue the lease for up to 21 more years.

Infrastructure

During 2010, we spent \$49 million on the construction of key infrastructure and the purchase of related equipment in the Narraway/Ojay fields. In late November 2010, we completed construction of a natural gas pipeline connecting shut-in wells from our Ojay acreage in British Columbia to sales meters in western Alberta. Our gas gathering system and associated facilities at the Narraway/Ojay fields were expanded in order to alleviate capacity restrictions, improve timely takeaway of our gas and enable us to proceed with our development plan. We believe that we have installed sufficient capacity to meet our near-term drilling plans for our assets in those fields and accommodate third-party volumes. At the Evi area, we have installed infrastructure that allows us to transport by pipeline the majority of our oil production, which has minimized the cost of trucking and the downtime associated with weather-dependent access to some locations. We intend to install, as needed, additional infrastructure in our core areas, which should allow us to continue to substantially control the pace of development, ensure timely takeaway of our production volumes and continue our commitment to improving operational efficiencies and cost control.

Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2011 and 2010. Our estimated proved reserves as of December 31, 2011 are based on the NYMEX Henry Hub price of US\$4.15 per MMBtu and AECO price of \$3.77 per MMBtu for natural gas and the NYMEX West Texas Intermediate price of US\$96.13 per barrel and Edmonton Light price of \$96.98 per barrel for oil, each of which represents the unweighted arithmetic average of the first-day-of-the-month prices during the 12-month period prior to December 31, 2011. Our estimated proved reserves as of December 31, 2010 are based on the NYMEX Henry Hub price of US\$4.38 per MMBtu and AECO price of \$3.93 per MMBtu for natural gas and the NYMEX West Texas Intermediate price of US\$79.81 per barrel and Edmonton Light price of \$77.80 per barrel for oil, each of which represents the unweighted arithmetic average of the first-day-of-the-month prices during the 12-month period prior to December 31, 2010. See "—*Preparation of Estimated Proved Reserves as of December 31, 2011*" below, "—*Preparation of Estimated Proved Reserves as of December 31, 2010*" below

and note 25 to our consolidated financial statements included elsewhere in this Form 10-K for additional information regarding our estimated proved reserves.

	Estimated Proved Reserves(1)					
	December 31, 2011			December 31, 2010		
	Natural gas (MMcf)	Oil and liquids (Mbbbls)	Total (MMcfe)	Natural gas (MMcf)	Oil and liquids (Mbbbls)	Total (MMcfe)
Developed	163,530	8,363	213,708	169,292	6,594	208,856
Undeveloped	131,939	9,200	187,136	97,594	11,663	167,572
Total estimated proved reserves	<u>295,469</u>	<u>17,563</u>	<u>400,844</u>	<u>266,886</u>	<u>18,257</u>	<u>376,428</u>

(1) Estimated proved reserves are based on anticipated sales volumes and do not contain those volumes of gas that we expect to be consumed in operations, flared or injected.

As of December 31, 2011, we had estimated proved reserves of 401 Bcfe. Our estimated proved reserves have a reserve life of 12 years, and our estimated proved developed reserves have a reserve life of six years. During 2011, we added a total of 24.2 Bcfe of estimated proved reserves. Additions were primarily due to additional reserve bookings in our Evi area associated with positive drilling results, and our acquisition of certain natural gas properties in the Narraway/Ojay fields on April 29, 2011. These additions were partially offset by revisions of previous estimates primarily due to the performance of existing wells and by production. As of December 31, 2011, proved undeveloped reserves (“PUDs”) were estimated to be 187 Bcfe, or 47% of total estimated proved reserves, compared to 168 Bcfe, or 45% of total estimated proved reserves, as of December 31, 2010. The net increase of 19 Bcfe was primarily due to successful drilling results in our Evi area. The additional PUD bookings were primarily from direct offsets to existing wells. We intend to convert the PUD reserves disclosed as of December 31, 2011 to proved developed reserves within five years of when they were initially disclosed as PUDs.

Our reserve estimates as of December 31, 2011 and 2010 presented herein were made in accordance with the SEC’s “Modernization of Oil and Gas Reporting” rules, which were effective for fiscal years ending on or after December 31, 2009. The new SEC rules include updated definitions of proved oil and gas reserves, proved undeveloped oil and gas reserves, oil and gas producing activities and other terms used in estimating proved oil and gas reserves. Pursuant to the SEC rules, proved oil and gas reserves as of December 31, 2011 and 2010 were calculated based on the prices for oil and natural gas during the 12-month period before the reporting date, determined as the unweighted arithmetic averages of the first-day-of-the-month prices for each month within such period, rather than the year-end spot prices, which had been used in years prior to 2009. Undrilled locations can be classified as having PUD reserves if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. The new SEC rules broadened the types of technologies that a company may use to establish reserve estimates and also broadened the definition of oil and gas producing activities to include the extraction of non-traditional resources, including bitumen extracted from oil sands, as well as oil and natural gas extracted from shales.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices or development and production expenses, may require revision of

such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates.

Preparation of Estimated Proved Reserves as of December 31, 2011

Independent Petroleum Engineers

Our estimated proved reserves at December 31, 2011 are based on a report dated February 3, 2012 prepared by DeGolyer and MacNaughton, our independent reserves engineers, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and current guidelines established by the SEC. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Calgary and Moscow. The firm's more than 140 professionals include engineers, geologists, geophysicists, petrophysicists and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies and equity studies related to the domestic and international energy industry. These services have been provided since 1936. DeGolyer and MacNaughton restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas or mineral properties or securities or notes of clients. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. The firm is a Texas Registered Engineering Firm. The Senior Vice President at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the reserve estimates is a Registered Petroleum Engineer in the State of Texas with more than 37 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1974, and he is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists.

Technology Used To Establish Proved Reserves

Under SEC rules, proved reserves are those quantities of oil and natural gas, which, 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 proved 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.

In order to establish reasonable certainty with respect to our estimated proved reserves, DeGolyer and MacNaughton 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, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well-test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using 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 were completed using similar techniques.

Internal Controls Over Reserves Estimation Process

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserves engineers to ensure the integrity, accuracy and timelines of data furnished to our independent reserves engineers in their reserves estimation process. Our Vice President, Engineering and Exploitation, Shona F. Mackenzie, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Ms. Mackenzie has over 17 years of industry experience with positions of increasing responsibility in engineering and evaluations and holds both a Bachelor of Engineering degree and a Master of Engineering degree in petroleum engineering. Ms. Mackenzie reports directly to our President and Chief Executive Officer, David M. Anderson.

Throughout each fiscal year, our technical team meets with representatives of our independent reserves engineers to review properties and discuss methods and assumptions used in the preparation of the proved reserves estimates. In addition, our management reports on a quarterly basis to our Audit and Reserves Committee, and our Audit and Reserves Committee meets privately with personnel from DeGolyer and MacNaughton on an annual basis to confirm that DeGolyer and MacNaughton has not identified any concerns or issues relating to its reserves estimates.

Preparation of Estimated Proved Reserves as of December 31, 2010

Our estimated proved reserves as of December 31, 2010 were prepared by the internal staff of engineers of Forest and LPR Canada, with significant consultation with internal geologists and geophysicists. The reserves estimates were based on production performance and data acquired remotely or in wells and were guided by petrophysical, geologic, geophysical and reservoir engineering models. Moreover, new reserves estimates and significant changes to existing reserves were reviewed and approved by various levels of management, depending on their magnitude. Proved reserves estimates were reviewed and approved by Forest's Senior Vice President, Business Development and Engineering, Glen Mizenko, and audited by independent reserve personnel from DeGolyer and MacNaughton to confirm that DeGolyer and MacNaughton had not identified any concerns or issues relating to the audit and maintained independence. In addition, Forest's internal audit department randomly selected a sample of new reserves estimates or changes made to existing reserves and tested to ensure that they were properly documented and approved.

As of December 31, 2010, Forest's Senior Vice President, Business Development and Engineering, Mr. Mizenko, had over 25 years of experience in oil and gas exploration and production and had served in this position at Forest since May 2007. Prior to that time, Mr. Mizenko held positions of increasing responsibility since joining Forest in early 2001. Prior to joining Forest, Mr. Mizenko held various positions in reservoir engineering, development planning and operations management with Shell Oil Company, Benton Oil and Gas Company and British Borneo Oil and Gas PLC. Mr. Mizenko received a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1985 and a Masters of Business Administration from the University of Houston in 1993. As of December 31, 2010, he was a 26-year member of the Society of Petroleum Engineers.

In the past, Forest engaged independent reserves engineers to audit a substantial portion of our reserves. Forest's audit procedures required the independent reserves engineers to prepare their own estimates of proved reserves for fields comprising at least 80% of the aggregate net present value of our year-end proved reserves, discounted to net present value ("NPV") at 10% per annum. The fields selected for audit also were required to comprise at least 80% of our fields based on the discounted present value of such fields and a minimum of 80% of the NPV added during the year through discoveries, extensions and acquisitions. The procedures prohibited exclusions of any fields, or any part of a field, that comprised part of the top 80%. The independent reserves engineers compared their estimates to those prepared by Forest's internal staff of engineers. Forest's audit guidelines required its

internal estimates, which were used for financial reporting purposes, to be within ten percent of the independent reserves engineers' quantity estimates in each country in which proved reserves were reported. The independent reserves audit was conducted based on the definition of reserves and cost and price parameters specified by the SEC.

For the years ended December 31, 2010 and 2009, we engaged DeGolyer and MacNaughton to perform reserve audit services. For the year ended December 31, 2010, DeGolyer and MacNaughton independently audited estimates relating to properties in our Narraway/Ojay, Wild River and Evi fields constituting approximately 81% of our reserves as of December 31, 2010. In the aggregate, Forest's and LPR Canada's estimates of total proved reserves for the fields audited were within ten percent of DeGolyer and MacNaughton's aggregate estimate of proved reserves. When compared on a field-by-field basis, Forest's and LPR Canada's estimates of proved reserves in our Narraway, Wild River and Evi fields were greater than the estimates prepared by DeGolyer and MacNaughton, and Forest's and LPR Canada's estimates of proved reserves in our Ojay field were less than the estimates prepared by DeGolyer and MacNaughton. In the aggregate, Forest's and LPR Canada's estimates of total proved reserves for the fields audited were 9.2 percent greater than the estimates prepared by DeGolyer and MacNaughton when compared on a net gas-equivalent basis. In its audit report, DeGolyer and MacNaughton stated that, in its opinion, the net proved reserves estimates prepared by Forest on the properties reviewed by DeGolyer and MacNaughton were reasonable. The lead technical person at DeGolyer and MacNaughton primarily responsible for overseeing the audit of our reserves was a Registered Professional Engineer in the State of Texas, was a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists and had in excess of 35 years of experience in oil and gas reservoir studies and reserves evaluations.

Drilling Activities

The following table summarizes the number of wells drilled during the years ended December 31, 2011, 2010 and 2009, excluding any wells drilled under farmout agreements, royalty interest ownership or any other wells in which we do not have a working interest. As of December 31, 2011, we had 2 gross (2 net) wells in progress. Our 2011 horizontal drilling program achieved a 100% success rate, and our 2010 drilling program achieved a 100% success rate due to the multiple number of reservoirs our wells penetrated during drilling in these particular fields.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Productive	51	50.5	39	27	7	3
Non-productive(1)	—	—	—	—	—	—
Total development wells	<u>51</u>	<u>50.5</u>	<u>39</u>	<u>27</u>	<u>7</u>	<u>3</u>
Exploratory wells, completed as:						
Productive	1	1	—	—	4	2
Non-productive(1)	<u>1</u>	<u>1</u>	—	—	—	—
Total exploratory wells	<u>2</u>	<u>2</u>	<u>—</u>	<u>—</u>	<u>4</u>	<u>2</u>

- (1) A non-productive well is a well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well; also known as a dry well (or dry hole). The non-productive well drilled in 2011 was a stratigraphic core well.

Oil and Gas Wells and Acreage

Productive Wells

Productive wells consist of producing wells and wells capable of production, including shut-in wells. A well bore with multiple completions is counted as only one well. The following table summarizes our productive wells as of December 31, 2011.

	December 31, 2011	
	Gross(1)	Net
Gas	513.0	343.5
Oil	364.0	305.0
Total	<u>877.0</u>	<u>648.5</u>

- (1) We owned interests in 261 gross wells containing multiple completions as of December 31, 2011.

Acreage

The following table summarizes developed and undeveloped acreage in which we owned a working interest or held an exploration license as of December 31, 2011. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary, as well as acreage related to any options held by us to acquire additional leasehold interests. At December 31, 2011, approximately 8%, 1% and 6% of our net undeveloped acreage was held under leases that will expire in 2012, 2013 and 2014, respectively, if not extended by exploration or production activities.

Location	December 31, 2011			
	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Deep Basin	97,410	51,421	155,948	106,358
Evi	17,000	12,334	47,320	45,048
Utica Shale	0	0	398,850	240,320
Liard Basin	0	0	53,788	52,995
Other	132,349	102,604	229,812	183,455
Total	<u>246,759</u>	<u>166,359</u>	<u>885,718</u>	<u>628,176</u>

Production, Average Sales Prices and Production Costs

	Year Ended December 31,		
	2011	2010	2009
Liquids:			
Oil:			
Average sales price (per bbl)	\$ 83.89	\$ 69.88	\$ 57.46
Net sales volumes (Mbbbls)	1,110	828	626
Natural gas liquids:			
Average sales price (per bbl)	\$ 61.43	\$ 53.65	\$ 34.93
Net sales volumes (Mbbbls)	82	134	230
Total liquids:			
Average sales price (per bbl)	\$ 82.34	\$ 67.62	\$ 51.41
Net sales volumes (Mbbbls)	1,192	962	856
Natural Gas:			
Average sales price (per Mcf)	\$ 3.42	\$ 3.84	\$ 3.59
Net sales volumes (MMcf)	27,167	22,436	23,248
Total liquids and natural gas:			
Average sales price (per Mcfe)	\$ 5.57	\$ 5.36	\$ 4.49
Total net sales volumes (MMcfe)	34,319	28,208	28,384
Production costs (per Mcfe):			
Lease operating expenses	\$ 1.13	\$ 0.94	\$ 1.10
Production and property taxes	0.07	0.09	0.11
Transportation and processing costs	0.50	0.39	0.33
Total production costs	<u>\$ 1.70</u>	<u>\$ 1.42</u>	<u>\$ 1.54</u>

The following table sets forth the net sales volumes (MMcfe) attributable to fields that contain 15% or more of our total estimated proved reserves as of the years ended December 31, 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	2010	2009
Narraway/Ojay	15,496	6,997	3,329
Wild River	7,179	9,792	9,372
Evi	<u>5,162</u>	<u>2,920</u>	<u>1,554</u>

Marketing and Delivery Commitments

Our natural gas production is generally sold on a month-to-month basis in the spot market, priced in reference to published indices. Our oil production is generally sold under short-term contracts at prices based upon refinery postings and is typically sold at or near the wellhead. Our natural gas liquids production is typically sold under term agreements at gas processing facilities at prices based on the average of posted prices less pipeline tariffs and fractionation fees. We believe that the loss of one or more of our current oil, natural gas or natural gas liquids purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption. As of March 20, 2012, we have a delivery commitment of approximately 21 BBTu/d of natural gas, which provides for a price equal to the greater of (1) the NYMEX Henry Hub price less US\$1.49 and (2) US\$1.00 per MMBtu to a buyer through

October 31, 2014, unless the NYMEX Henry Hub price exceeds US\$6.50 per MMBtu, at which point we share the amount of the excess equally with the buyer. Approximately 90% of our current natural gas production, or approximately 60 MMcfe/d, in Alberta and British Columbia is available to be used as source gas for this delivery commitment.

Competition

We encounter competition in all aspects of our business, including acquisition of properties and oil and gas leases, marketing oil, natural gas and NGLs, obtaining services and labor and securing drilling rigs and other equipment necessary for drilling and completing wells. Our ability to increase reserves in the future will depend on our ability to generate successful prospects on our existing properties, execute on major development drilling programs and acquire additional leases and prospects for future development and exploration. A large number of the companies that we compete with have substantially larger staffs and greater financial and operational resources than we have. Because of the nature of our oil and gas assets and management's experience in exploiting our reserves and acquiring properties, management believes that we effectively compete in our markets. See Part I, "Item 1A. Risk Factors—Risks Related to Our Business—*Competition within our industry is intense and may have a material adverse effect on our business, financial condition, cash flows and results of operations.*"

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment, thereby limiting or temporarily halting our drilling and producing activities and other oil and gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the winter months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Industry Regulation

The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and our oil and gas operations are subject to various Canadian federal, provincial, territorial and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure, the exploration and development of hydrocarbon resources and production, handling, storage, transportation and disposal of oil and gas, oil and gas by-products and other substances and materials produced or used in connection with oil and gas operations. More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling and completion of wells, the method and ability to produce from wells, surface usage, transportation of production, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties and royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, loss or cancellation of governmental or regulatory approvals and the issuance of injunctions or similar orders that could delay, limit or prohibit certain of our operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil, natural gas and NGLs that may be removed from the provinces and exported from Canada in certain circumstances. At various times, regulatory agencies have imposed price controls and limitations on oil and natural gas production. In order to conserve supplies of oil and natural gas, these agencies may also restrict the rates of flow of oil and natural gas wells below actual production capacity. Further, a significant spill from one of our facilities could have a material adverse effect on our business, financial condition, cash flows and results of operations.

We do not expect that any of these regulatory controls and restrictions will affect us in a manner significantly different from other oil and gas companies of similar size with operations in Canada.

Royalties

General

Each of the provinces and territories in which we operate has legislation and regulations governing royalties, land tenure, production rates and taxes, environmental protection and other matters under their respective jurisdictions. The royalty regime applicable in the provinces and territories in which we operate is a significant factor in the profitability of our production. Crown royalties payable in respect of production from Crown, or public, lands are determined by government regulation and are typically calculated as a percentage of the value of production. The value of production and the rate of royalties payable depend on prescribed reference prices, well productivity, geographical location and the type of product produced.

Royalties payable on production from privately-owned lands are determined by negotiations between us and the resource owners. Any such royalties (or royalty-like interests) are carved out of the working interest owner's interest through non-public transactions and are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

Governments sometimes adopt incentive programs to stimulate oil and gas exploration and development activity in their jurisdictions, which may include royalty rate reductions, drilling credits, royalty holidays or royalty tax credits. Such programs are often of limited duration and target specified types of oil and gas activities.

Alberta

The majority of our current oil and gas production is from properties located in Alberta.

On October 25, 2007, the Government of Alberta released its New Royalty Framework ("NRF") proposals, which included significant changes to Alberta's oil and gas royalty system. The NRF was implemented on January 1, 2009. On March 11, 2010, the Government of Alberta announced further adjustments to the royalty framework, reducing maximum royalty rates and making certain temporary incentive programs permanent effective January 1, 2011, and re-naming the NRF the Alberta Royalty Framework ("ARF").

The NRF established new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the NRF (now ARF), the royalties payable for conventional oil and natural gas are derived using sliding rate formulae, which incorporate a market price component and a production volume component.

In November 2008, in connection with the implementation and phase-in of the NRF, the Government of Alberta announced a five-year program of "transitional" royalty rates providing for lower royalties at certain price points in the initial years of a qualifying well's life. Under the transitional royalty program, companies drilling new natural gas and conventional oil deep wells at

depths between 1,000 meters and 3,500 meters (3,281 feet and 11,483 feet, respectively) spud after November 19, 2008 had a one-time option, on a well-by-well basis, to elect for the production from such wells to be subject to the transitional royalty rates or those provided for under the NRF. The option for producers to elect for transitional royalties in respect of qualifying deep wells ended on December 31, 2010. Any wells spudded on or after January 1, 2011 are subject to the royalty rates provided for under the ARF. Wells that are subject to transitional royalty rates will automatically revert to ARF rates on January 1, 2014.

Under the ARF, royalty rates for conventional oil currently range from 0% to 40%, and royalty rates for natural gas (methane and ethane) currently range from 5% to 36%. ARF rates for propane and butane are fixed at 30%, and the rate for pentane is fixed at 40%. Condensate royalties under the ARF are calculated on a basis similar to royalties for conventional oil and currently range from 0% to 40%.

The Government of Alberta has also introduced a number of royalty reduction and credit incentive programs to encourage oil and gas exploration and development in Alberta, which include the following programs currently in effect:

- The New Well Royalty Rate (“NWRR”) creates incentives for new wells that commence production on or after April 1, 2009. Other wells may also qualify for the NWRR depending on the periods for which they were previously shut-in or producing prior to April 1, 2009. Eligible wells under the NWRR are subject to a flat royalty rate of 5% for the first 12 months of production to a maximum of 500 MMcf of natural gas or 50,000 bbls of oil. The NWRR was originally announced in March 2009 as a temporary measure but was made permanent (subject to the same 12-month time and specified volume limitations) on March 11, 2010.
- The Deep Oil Exploration Program provides royalty relief of up to \$1,000,000 or 12 months of production, whichever comes first, for qualifying deep exploration oil wells with a true vertical depth greater than 2,000 meters (6,562 feet) that spud on or after January 1, 2009. Wells drilled after December 31, 2013 will not qualify for relief under this program, and the relief will expire on December 31, 2018.
- The Natural Gas Deep Drilling Program, as revised effective May 1, 2010, provides for a sliding scale production royalty credit for qualifying deep exploration and development gas wells with a true vertical depth greater than 2,000 meters (6,562 feet) that spud on or after May 1, 2010. The production credit is calculated according to the measured (drilled) depth to the bottom of the lowest producing interval of the qualifying wells and increases at certain trigger depths. The credit ranges from \$625 per meter (\$191 per foot) to a maximum of \$3,000 per meter (\$914 per foot) for a qualifying development well and \$3,750 per meter (\$1,143 per foot) for a qualifying exploration well. A minimum 5% royalty will apply to these gas wells.

On May 27, 2010, the Government of Alberta announced a number of additional incentive programs for qualifying wells coming on production after May 1, 2010, as follows:

- the Shale Gas New Well Royalty Rate, which extends the 5% NWRR on qualifying shale gas wells from 12 months to 36 months and removes the 500 MMcf volume limit;
 - the Coalbed Methane New Well Royalty Rate, which extends the 5% NWRR on qualifying coalbed methane wells from 12 months to 36 months and increases the 500 MMcf volume limit to 750 MMcf;
 - the Horizontal Gas New Well Royalty Rate, which extends the 5% NWRR on qualifying horizontal gas wells from 12 months to 18 months and maintains the 500 MMcf volume limit;
- and

- the Horizontal Oil New Well Royalty Rate, which extends the 5% NWRR on qualifying horizontal oil wells from 12 months to a minimum of 18 months and increases producing time and volume limits according to the measured depth of the well's qualifying interval to a maximum of 48 months or 100,000 bbls, respectively.

British Columbia

After Alberta, the remainder of our current oil and gas production is from properties located in British Columbia.

The British Columbia royalty regime for natural gas produced on Crown lands is price-sensitive and determined by a sliding scale formula based on a reference price, which is the greater of the producer price and a prescribed minimum price. The Government of British Columbia determines the producer price by averaging the actual selling prices for gas sales with shared characteristics for each company minus applicable costs. Natural gas in British Columbia is classified as either "conservation gas" or "non-conservation gas." There are three royalty categories applicable to non-conservation gas (not produced in association with oil), which are dependent on the date on which title was acquired from the Crown and the date on which the well was drilled. The royalty rate may also be impacted by the select price, a parameter in the royalty rate formula to account for inflation. The base royalty rate for non-conservation gas ranges from 9% to 15%. A lower base royalty rate of 8% is applied to conservation gas as an incentive to produce gas that might otherwise have been flared. The royalty rate may be reduced for low productivity wells.

The British Columbia royalty regime for oil is dependent on the type and age of the oil and the quantity produced. Oil is classified as "old," "new" or "third tier" depending on the discovery date of the pool from which the oil is produced, and a different formula is used to determine the royalty rate depending on the classification. Royalty rates are further varied depending on production. Lower royalty rates apply to low productivity wells and third-tier oil (produced from pools discovered after June 1, 1998) to reflect the increased cost of exploration and extraction.

As with the Government of Alberta, the Government of British Columbia has introduced a number of oil and natural gas royalty reduction and credit incentive programs to encourage oil and gas exploration and development in British Columbia. Currently included among these programs are the following:

- The Summer Royalty Program provides a royalty credit of 10% of drilling and completion costs to a maximum of \$100,000 per well for qualifying wells spud between April 1 and November 30 of each year.
- The Deep Royalty Program and Deep Re-Entry Royalty Program provide royalty credits for qualifying deep vertical wells with a true vertical depth greater than 2,500 meters (8,202 feet) and horizontal wells with a true vertical depth greater than 1,900 meters (6,234 feet), which spud after August 31, 2009, and for deep re-entry wells with a true vertical depth greater than 2,300 meters (7,546 feet) and a re-entry date after December 31, 2003. The royalty credit is calculated according to the measured (drilled) depth of the qualifying well and associated drilling costs.
- The Deep Discovery Royalty Program provides for a three-year royalty holiday or 283,000,000 m³ (10,000 MMcf) of royalty-free gas production, whichever comes first, for qualifying deep discovery wells with a true vertical depth greater than 4,000 meters (13,123 feet) that have finished drilling after November 2003 and whose surface locations are at least 20 kilometers (12.4 miles) away from the surface location of any well in a recognized pool of the same formation.
- The Coalbed Gas Royalty Program provides a royalty reduction for coalbed gas wells with average daily production less than 17,000 m³ (0.6 MMcf), as well as a royalty credit for coalbed

gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for coalbed gas wells drilled on freehold land.

- The Marginal Royalty Program provides a royalty reduction for low productivity natural gas wells with an average production rate of under 25,000 m³/d (0.88 MMcf/d) during the first 12 months of production and an average daily production rate of less than 23 m³/d (0.80 Mcf/d) for every 1 meter (3.28 feet) of depth to the applicable zone.
- The Ultra-Marginal Royalty Program provides additional royalty breaks for low productivity, shallow natural gas wells with a true vertical depth of less than 2,300 meters (7,546 feet) if horizontal or less than 2,500 meters (8,202 feet) if vertical, an average production volume of under 60,000 m³/d (2,130 Mcf/d) during the first 12 months of production and an average daily production rate of less than 11.5 m³/d (0.4 Mcf/d) for development wells or 17 m³/d (0.6 Mcf/d) for exploratory wildcat wells, for every 1 meter (3.28 feet) of depth to the applicable zone.
- The Net Profit Royalty Program targets the development and commercialization of technically complex resources in British Columbia, such as coalbed gas, tight gas, shale gas, enhanced oil recovery or resources that are remote from existing infrastructure, and provides for a reduction in initial royalty rates while a producer is recovering capital costs in exchange for higher royalty rates once these costs have been recovered. The program allows for the calculation of royalties based on the net profits of a particular project.
- The Infrastructure Royalty Credit Program provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects.

Quebec

Although oil and gas exploration and development in Quebec is subject to regulation under various laws and regulations, there is not yet a legislative and regulatory regime in Quebec that is specific to the oil and gas industry. Royalties are currently set pursuant to regulation made under the province's mining laws, which prescribe that royalty rates of 5% to 12.5% for crude oil and 10% to 12.5% for natural gas apply, depending on the quantity produced.

The Government of Quebec, which had been expected to introduce new oil and gas legislation sometime in the spring of 2011, has postponed the adoption of new rules for shale gas exploration and development pending completion of the SEA announced on March 8, 2011. See “—Environmental Regulation” below. It is unclear whether any portions of the new legislation will be introduced before completion of the SEA, which is currently expected to take 18 to 30 months to complete. The first SEA committee report is due in May 2012.

The Government of Quebec also announced on March 17, 2011, a proposal to introduce a new shale gas royalty regime that would come into effect once the SEA has been completed and the legal and regulatory framework has been adapted to its conclusions. The details of this proposal are summarized in “A Fair and Competitive Royalty System for Responsible Shale Gas Production,” which was presented as part of the 2011-2012 budget proposal.

The proposal includes the following measures:

- The new royalty regime proposes a progressive royalty rate, calculated on a per well basis, ranging from 5% to 35% for shale gas. The applicable rate will be determined according to a formula that is based on the price of natural gas (with the price component expected to take into account market price, transportation cost, processing cost and other items, with terms and conditions still to be specified) and the well's productivity (with the production component expected to be based on average daily production volume for a given month).

- The current provincial 15% tax credit for resources will be eliminated with respect to shale gas exploration and replaced by a non-refundable royalty credit for exploration, the exact terms and conditions of which will be announced at a later date but are expected to apply to an individual well and generally provide for a royalty credit of up to 15% of eligible exploration expenses, subject to a minimum royalty rate of 5% and an ability to carry forward any unused portion of the credit to a subsequent year for the same well.
- Businesses that have completed wells before introduction of the new system will be able to continue operating under the current royalty regime throughout the production life of those wells, even after the new royalty regime takes effect.
- The government will also introduce a gas development program, the stated objective of which is to encourage exploration by allowing businesses to pay lower royalties in the initial development and commercialization stages of authorized projects in exchange for progressively higher royalties once they have recouped their investments. The program would provide for a minimum royalty of 2% of gross revenue starting at the time that a well is brought into production until eligible investment and operating costs plus interest have been recouped (subject to a maximum of ten years of rate relief), and increased rates thereafter. After eligible investment and operating costs plus interest have been recouped or ten years, whichever comes first, royalty rates would increase to the higher of 5% of gross revenue and (1) 15% of net revenue, until the business has achieved a 25% rate of return plus interest on its initial investment, (2) 20% of net revenue, until the business has achieved a 100% rate of return plus interest on its initial investment and (3) 25% of net revenue after the business has achieved a 100% rate of return plus interest on its initial investment.
- During the transition period leading to introduction of the new royalty regime, businesses will have the option of continuing under the current royalty system or participating in the new gas development program. Businesses participating in the SEA will also be allowed to make their wells subject retroactively to the gas development program.
- In addition to royalty-related measures, the government announced that municipalities will be compensated for quantifiable additional costs attributable to shale gas exploration and production and would also receive \$100,000 for each shale gas well operated on its territory, to be paid over a ten-year period, in each case to be financed by industry in a manner yet to be determined.

Northwest Territories

Royalties payable on production from Crown land in the Northwest Territories are reserved to the Canadian federal government and are payable once production from project lands has commenced (being the time at which the petroleum products become marketable). Royalties are not payable during the pre-production period when activities such as exploration, testing and drilling are being conducted.

Crown royalty rates are calculated with reference to whether payout (being the point at which the cumulative adjusted gross revenue from the property exceeds adjusted cumulative costs) has been reached. Prior to payout, royalties are payable on a graduated monthly basis. For the first 18 months of production, the royalty rate is 1% of gross revenues, increasing to 2% of gross revenues from the 19th to the 36th month after production has commenced, to 3% of gross revenues from the 37th to the 54th month, to 4% of gross revenues from the 55th to the 72nd month and to 5% of gross revenues from the 73rd month until payout is achieved. Once payout is achieved, the monthly royalty is fixed at the greater of 30% of net revenues and 5% of the gross revenues of the project.

Land Tenure

The majority of oil and natural gas resources located in the provinces of Alberta, British Columbia and Quebec and in the Northwest Territories are owned by the respective provincial governments and, in the case of the Northwest Territories, the Canadian federal government. Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses and permits and regulations as issued by the applicable governments. Lease terms vary in length from two years and longer. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Jurisdictions in Canada, including the provinces of Alberta and British Columbia, have legislation in place for mineral rights reversion to the Crown of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to “continue” lease terms for non-productive lands, having met certain criteria as laid out in the relevant legislation.

Environmental Regulation

As an operator of oil and gas properties in Canada, we are subject to stringent federal, provincial, territorial and local laws and regulations relating to environmental protection, as well as controlling the manner in which various substances, including wastes, generated in connection with oil and gas exploration, production and transportation operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed and require proper abandonment of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, imposition of remedial obligations, incurrence of capital or increased operating costs to comply with governmental standards and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

We currently operate or lease, and have in the past operated or leased, a number of properties that for many years have been used for the exploration and production of oil and natural gas. Although we utilize and have utilized standard industry operating and disposal practices, hydrocarbons or other wastes, may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability, without regard to fault or the legality of the original conduct, that could require us to remove previously disposed wastes or remediate property contamination or to perform well plugging or pit closure or other actions of a remedial nature to prevent future contamination.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe that we are in substantial compliance with applicable environmental laws and regulations currently in effect and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance with respect to the effect on us of future legislative or regulatory initiatives or changes or that we will not be adversely affected in the future by new requirements, whether as a result of the direct or indirect costs of compliance or restrictions on the extent to which exploration and development may be allowed. Examples of such initiatives or changes and new requirements have occurred in Quebec and British Columbia with respect to shale gas exploration and development. In Quebec, the government announced in March 2011 an 18- to 30-month SEA of shale gas activities in the province during which hydraulic fracturing will be allowed only if required for SEA purposes. The particulars of any further

prohibitions, restrictions or other requirements, including their duration, transitional provisions and exceptions, if any, that may arise from the SEA are not yet known. In June 2011, Quebec enacted legislation that revokes previously issued exploration licenses for the St. Lawrence River upstream of Anticosti Island and the islands therein. In British Columbia, the government introduced mandatory public disclosure of hydraulic fracturing fluid ingredients as of January 1, 2012 and established an online registry providing public access to information on fractured well locations and hydraulic fracturing fluid ingredients. At a media briefing held in late February 2012 regarding current regulations governing hydraulic fracturing operations in Alberta, representatives of the province's principal oil and gas regulatory agency, the Energy Resources Conservation Board ("ERCB"), were reported to have advised that the ERCB expects to implement rules requiring public disclosure of hydraulic fracturing fluid ingredients before the end of 2012. We have established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which we operate. We employ an environmental, health and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance against the costs of cleanup operations, public liability and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

Climate Change Regulation

Federal (Canada)

Internationally, Canada is a signatory to the United Nations Framework Convention on Climate Change ("Framework Convention") and previously ratified the Kyoto Protocol established thereunder, which set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHGs"). The first commitment period under the Kyoto Protocol is the five-year period from 2008 to 2012. In December 2011, however, the Canadian federal government announced that it would not agree to a second commitment period under the Kyoto Protocol after 2012. The federal government instead endorsed the Durban Platform, a broad agreement reached among the 194 countries that are party to the Framework Convention during a conference held in Durban, South Africa in December 2011. The Durban Platform sets forth a process for negotiating a new climate change treaty that would create binding commitments for all major GHG emitters. The Canadian government expressed cautious optimism that agreement on a new treaty can be reached by 2015. The Durban Platform followed the Copenhagen Accord reached in December 2009 as the parties to the Kyoto Protocol met in Copenhagen, Denmark to negotiate a successor. Although no binding agreement was reached, several countries, including Canada and the United States, committed to the Copenhagen Accord, which represents a broad political consensus and reinforces commitments to reducing GHG emissions but is not a legally binding international treaty. Canada has committed under the Copenhagen Accord to reduce its GHG emissions by 17% from 2005 levels by 2020, which is consistent with the commitment of the United States, but the target is not legally binding. The impact of Canada's withdrawal from the Kyoto Protocol on prior GHG emission reduction initiatives is uncertain.

Domestically, the Canadian federal government released in 2007 its Regulatory Framework for Air Emissions, which was updated in March 2008 in a document entitled "Turning the Corner: Regulatory Framework for Industrial Greenhouse Emissions" that set out a GHG emission reduction target of 20% from 2006 levels by 2020. On January 30, 2010, the Canadian federal government announced a new GHG emission reduction target, consistent with its commitment under the Copenhagen Accord, to reduce GHG emissions by 17% from 2005 levels by 2020. Canada's regulatory framework proposes mandatory reduction obligations on GHG emissions intensity (i.e., the quantity of GHG emissions per unit of production) on a sector-by-sector basis. Although implementing regulations are required, to date only regulations for Canada's transportation and electricity sectors have been developed. In 2009, the

Canadian federal government announced its commitment to work with the provincial governments to implement a North America-wide cap and trade system for GHG emissions, in cooperation with the United States, under which Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. The Canadian federal government currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether or when either Canadian federal GHG regulations for the oil and gas industry or an integrated North American cap-and-trade system will be implemented, what obligations might be imposed under any such systems or how they may ultimately affect our operations and financial results.

Alberta

Alberta introduced the Climate Change and Emissions Management Act, which provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulation, the Specified Gas Emitters Regulation (“SGER”), effective July 1, 2007, applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year and requires reductions in GHG emissions intensity from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between “established” facilities that completed their first year of commercial operation before January 1, 2000 or have completed eight years of commercial operation, and “new” facilities that completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004 and 2005, and for a new facility emissions intensity in the third year of commercial operation. For an established facility, the required reduction in GHG emissions intensity is 12% per year from its baseline, and such reduction must be maintained over time. For a new facility, the required reduction from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the annual 12% reduction requirement is reached, and once reached, such 12% reduction must be maintained over time.

There are three methods for operators of facilities that are subject to the SGER to comply with the annual emission intensity reduction requirements: improve emissions intensity at the facility; purchase emission performance or emission offset credits in the open market, which are generated from Alberta-based projects; and/or purchase “fund credits” by contributing to the Alberta Climate Change and Emissions Management Fund run by the Government of Alberta. Contribution costs to this fund have historically been \$15 per tonne of carbon dioxide equivalent (“CO₂e”) but are now set by provincial government order. Compliance reports for facilities subject to the SGER are due to Alberta Environment on March 31 annually.

The Specified Gas Reporting Regulation imposes GHG emissions reporting requirements on facilities that have GHG emissions of 50,000 tonnes or more in a year. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations in permits and under other environmental regulations. Alberta announced in January 2008 a new climate change plan setting out a goal of achieving a 14% absolute reduction in GHG emissions below 2005 levels in the province by 2050. The direct and indirect costs of these regulations or any amendments thereto may adversely affect our operations and financial results.

British Columbia

Pursuant to the Greenhouse Gas Reduction Targets Act, British Columbia has set a goal of reducing its GHG emissions to 33% below 2007 levels by 2020, with interim targets of 6% below 2007 levels by 2012 and 18% below 2007 levels by 2016. The provincial government is required under that

legislation to report every second year on the amount of reductions achieved in the province. In June 2008, British Columbia released its Climate Action Plan, which outlines a number of strategies and initiatives to take British Columbia approximately 73% towards meeting the goal of reducing GHG emissions by 33% below 2007 levels by 2020. The province has also enacted framework legislation providing for a provincial cap and trade system and has imposed GHG emissions reporting requirements under the Greenhouse Gas Reduction (Cap and Trade) Act and the Reporting Regulation. Additionally, British Columbia has implemented a carbon tax on the purchase or use of fossil fuels within the province, starting at \$10 per tonne of CO₂e emissions from the combustion of each fuel commencing on July 1, 2008 and rising by \$5 per year to \$30 per tonne in 2012. Requirements that may be imposed in British Columbia may have adverse operational or financial consequences for our business.

Quebec

Quebec recently indicated that, following a consultation period that ended in late February 2012, it is nearing completion of a 2013-2020 Climate Change Action Plan that will include measures for reducing GHG emissions, with a previously-announced GHG emission reduction target of 20% below 1990 levels by 2020. The new plan is to build on the current 2006-2012 Climate Change Action Plan, which called for governmental actions to reduce GHG emissions to 6% below 1990 levels by 2012 and included fuel oil energy efficiency measures, measures to encourage cleaner energy alternatives and tightened fuel oil sulphur level standards but no enforceable GHG emission reduction targets. Pursuant to regulation under the Environmental Quality Act, Quebec is implementing a cap-and-trade system for GHG emission allowances with the initial compliance period to commence January 1, 2013 for certain operators with annual GHG emissions of 25,000 tonnes or more of CO₂e. Prior to implementation of the initial capping and reduction requirements, emitters and participants will be able to take part in pilot auctions and trade GHG emission allowances. Quebec has also enacted a carbon tax on the consumption of fossil fuels in the province. The effect of Quebec's cap-and-trade system and other measures undertaken in furtherance of its Climate Change Action Plan on the oil and gas industry is uncertain at this time, and such actions may have adverse operational or financial consequences for our business.

Northwest Territories

In August 2011, the Government of the Northwest Territories released "A Greenhouse Gas Strategy for the NWT 2011-2015," which targets to stabilize GHG emissions at 2005 levels by 2015, to limit GHG emission increases to 66% above 2005 levels by 2020 and to return GHG emissions to 2005 levels by 2030. The effect of any implementation of this policy on oil and gas operations is not clear, and governmental action taken to fulfill it could adversely affect our operations and financial results.

Title to Properties

Title to our oil and gas properties may be subject to royalty, overriding royalty, carried, net profits, working and similar interests customary in the oil and gas industry. Under the terms of the credit agreement governing our bank credit facility, LPR Canada granted the lenders a lien on substantially all of our properties. In addition, our properties may also be subject to liens incident to operating agreements, as well as other customary encumbrances, easements and restrictions, and for current taxes not yet due. Our general practice is to conduct a title examination on material property acquisitions. Prior to the commencement of drilling operations, a title examination and, if necessary, curative work is performed. The methods of title examination that we have adopted are reasonable in the opinion of management and are designed to ensure that production from our properties, if obtained, will be salable for our account.

Employees

As of December 31, 2011, we had 71 employees. None of our employees is currently represented by a union for collective bargaining purposes. We consider our relations with our employees to be satisfactory. From time to time, we utilize the services of independent contractors to perform various field and other services.

Offices

As of December 31, 2011, we leased approximately 43,495 square feet of office space in Calgary, Alberta at 640-5th Avenue SW, where our principal offices are located. The lease for our Calgary office expires February 1, 2022. We also lease or own field offices in the areas in which we conduct our operations.

Internet Web Site and Availability of Public Filings

Our internet address is www.lonepineresources.com. We file and furnish Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, and amendments to these reports, with the SEC, which are available free of charge through our website as soon as reasonably practicable after such reports are filed with or furnished to the SEC.

Materials we file with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet website at <http://www.sec.gov> that contains reports, proxy and information statements and other information regarding our company that we file with and furnish electronically to the SEC.

We may from time to time provide important disclosures to investors by posting them in the investor relations section of our website, as allowed by SEC rules. Information on our internet website is not incorporated by reference into this Form 10-K, and you should not consider information on our website as part of this Form 10-K.

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Form 10-K. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a) of Regulation S-X. The entire definitions of those terms can be viewed on the website of the SEC at <http://www.sec.gov>.

AECO. The Alberta gas trading price.

bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

BBtu. One billion British Thermal Units.

Btu. A British Thermal Unit, or the amount of heat necessary to raise the temperature of one pound of water one degree Fahrenheit.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or held by producing wells or wells capable of production.

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

Dry hole; dry well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Equivalent volumes. Equivalent volumes are computed with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

Exploitation. Ordinarily considered to be a form of development within a known reservoir.

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 gas in another reservoir. Generally, an exploratory well is any well that is not a development well or a service well.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location or the undertaking of other work obligations.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Full cost pool. The full cost pool consists of all costs associated with property acquisition, exploration and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general and administrative expense or similar activities are not included.

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

Hydraulic fracturing. A process used to stimulate production of hydrocarbons. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

Liquids. Describes oil, condensate and natural gas liquids.

Mbbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

MMBtu. One million British Thermal Units, a common energy measurement.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate, or natural gas liquids.

MMcfe/d. MMcfe per day.

NGL. Natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers and fractions of whole numbers.

Net production. The working interest production less the amount of production attributable to royalty burdens.

NYMEX. New York Mercantile Exchange.

Productive wells. Producing wells and wells that are capable of production, including injection wells, salt water disposal wells, service wells and wells that are shut-in.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. Quantities of oil and gas, which, 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Existing economic conditions include prices that are the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves. Estimated 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 recovery to occur.

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

Standardized measure of discounted future net cash flows. An estimate of the present value of the estimated future net revenues from proved oil and gas reserves at a date indicated after deducting estimated production and property taxes, future capital costs, operating expenses and estimated future income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC's requirements, to determine their "present value." The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the estimation date in accordance with the SEC's rules and regulations and are held constant for the life of the reserves.

Undeveloped acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Working interest. An operating interest which gives the owner the right to drill, produce and conduct operating activities on the property, and to receive a share of production.

Working interest production. The working interest share of production before the impact of royalty burdens.

Item 1A. Risk Factors.

We are subject to certain risks and hazards due to the nature of the business activities we conduct, including the risks discussed below. The risks discussed below, any of which could materially and adversely affect our business, financial condition, cash flows and results of operations, are not the only risks we face. We may experience additional risks and uncertainties not currently known to us; or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows and results of operations. If any of the following risks actually occurs, our business, financial condition, cash flows and results of operations could suffer materially and adversely, and our ability to implement business plans or complete development activities as scheduled could be impaired. In that case, the market price of the Company's common stock could decline.

Risks Related to Our Business

Oil, natural gas and NGL prices and related differentials are volatile. Declines in commodity prices have adversely affected our business, financial condition, cash flows, results of operations and ability to grow and in the future may adversely affect our business, financial condition, cash flows, results of operations, access to the capital markets and ability to grow.

Our financial condition, operating results and future rate of growth depend upon the prices that we receive for our oil, natural gas and NGLs. Prices also affect our cash flow available for capital expenditures and our ability to access funds under our bank credit facility and through the capital markets. The amount available for borrowing under our bank credit facility is subject to a borrowing base, which is determined by our lenders taking into account our estimated proved reserves, and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. Declines in oil, natural gas and NGL prices may adversely impact the value of our estimated proved reserves and, in turn, the bank pricing used by our lenders to determine our borrowing base. See Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—*Bank Credit Facility*" for more details. Further, because we have elected to use the full cost accounting method, each quarter we must perform a "ceiling test" that is impacted by declining prices. Significant price declines could cause us to take one or more ceiling test write-downs, which would be reflected as non-cash charges against current earnings. See "*—Lower oil, natural gas and NGL prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values.*"

Further, the differentials between (1) the prices that we realize for our oil, natural gas and NGLs and (2) commonly used benchmark prices for each product, are volatile and will change over time.

In addition, significant or extended price declines may also adversely affect the amount of oil, natural gas and NGLs that we can produce economically. A reduction in production could result in a shortfall in our expected cash flows and require us to reduce our capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively impact our ability to replace our production and our future rate of growth.

The markets for oil, natural gas and NGLs have been volatile historically, and we expect them to remain volatile in the future. Oil and natural gas spot prices reached at or near historical highs in July 2008. Prices have declined since that time and may continue to fluctuate widely in the future. During the fourth quarter of 2011 and continuing into 2012, natural gas prices declined to ten year lows. As of March 20, 2012, the spot price for natural gas was US\$2.32 per MMBtu for NYMEX Henry Hub and \$1.89 per MMBtu for AECO, and the spot price for crude oil was US\$105.61 per barrel for NYMEX

West Texas Intermediate and \$94.76 per barrel for Edmonton Light. The prices we receive for our oil, natural gas and NGLs depend upon factors beyond our control, including, among others:

- domestic and global supplies, consumer demand for oil, natural gas and NGLs and market expectations regarding supply and demand;
- domestic and worldwide economic conditions;
- the impact of the U.S. dollar and the Canadian dollar exchange rate on oil, natural gas and NGL prices;
- the proximity, capacity, cost and availability of oil, natural gas and NGL pipelines, processing, gathering and other transportation facilities;
- weather conditions;
- political conditions, instability and armed conflicts in oil-producing and gas-producing regions;
- actions by the Organization of Petroleum Exporting Countries directed at maintaining prices and production levels;
- the price and availability of imports of oil, natural gas and NGLs;
- the impact of energy conservation efforts and the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxes; and
- technological advances affecting energy consumption and supply.

These factors make it very difficult to predict future commodity price movements with any certainty. We sell the majority of our oil, natural gas and NGL production at current spot prices rather than through fixed-price contracts. However, we enter into, and we intend in the future to enter into, additional derivative instruments to reduce our exposure to fluctuations in oil, natural gas and NGL prices. See “—*Our use of hedging transactions could result in financial losses or reduce our income.*” Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Approximately 74% of our estimated proved reserves at December 31, 2011 were natural gas, and, as a result, our financial results will be more sensitive to fluctuations in natural gas prices.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy.

We require substantial capital expenditures to conduct our exploration, development and production operations, engage in acquisition activities and replace our production. As part of our exploration and development operations, we have expanded, and expect to further expand, the application of horizontal drilling and multi-stage hydraulic fracture stimulation techniques. The utilization of these techniques requires substantially greater capital expenditures as compared to the drilling of a vertical well, sometimes more than three times the cost. The incremental capital expenditures are the result of greater measured depths and additional hydraulic fracture stages in horizontal wellbores. We have established a capital budget for 2012 of approximately \$200 million to \$220 million, which includes approximately \$165 million for our capital program in the Evi area in 2012. We plan to use cash flow from operating activities and borrowings under our bank credit facility to fund our capital expenditures in 2012. We also may engage in asset sale transactions to fund capital expenditures when market conditions permit us to complete transactions on terms we find acceptable.

We intend to rely on cash flow from operating activities and borrowings under our bank credit facility as our primary sources of liquidity. There can be no assurance that such sources will be sufficient to fund our exploration, development and acquisition activities. Our ability to access the

private or public equity capital markets or complete asset sales to fund such activities is subject to certain limitations related to our spin-off from Forest. If our revenues and cash flows decrease in the future as a result of a decline in commodity prices or a reduction in production levels, however, and we are unable to obtain additional equity or debt financing in the private or public capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to replace our reserves or maintain our production levels.

Our future revenues, cash flows and spending levels are subject to a number of factors, including commodity prices, the level of production from existing wells and our success in developing and producing new wells. Further, our ability to access funds under our bank credit facility is based on a borrowing base, which is subject to periodic redeterminations based on our estimated proved reserves and prices that will be determined by our lenders using the bank pricing prevailing at such time. If the prices for oil and natural gas decline, or if we have a downward revision in estimates of our proved reserves, our borrowing base may be reduced. See Part II, “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—*Bank Credit Facility*” for more details.

Our ability to access the private and public equity and debt markets and complete future asset monetization transactions is also dependent upon oil, natural gas and NGL prices, in addition to a number of other factors, some of which are outside our control. These factors include, among others:

- the value and performance of our equity securities;
- domestic and global economic conditions; and
- conditions in the domestic and global financial markets.

In addition, in connection with the completion of our IPO, we entered into separation agreements with Forest to preserve the tax-free status of our spin-off from Forest. As a result, we are restricted in our ability to sell assets outside the ordinary course of business, to issue or sell our common stock or certain other securities (including securities convertible into our common stock but excluding certain compensation arrangements) or to enter into any other corporate transaction that would cause us to undergo either a 50% or greater change in the ownership of our voting stock or a 50% or greater change in the ownership (measured by value) of all classes of our stock. See “—Risks Related to Our Separation from Forest—*The separation agreements may limit our ability to obtain additional financing or make acquisitions and may require us to pay significant tax liabilities.*”

The credit crisis and related turmoil in the global financial markets have had an impact on our business and our financial condition, and we may face additional challenges if economic and financial market conditions worsen. The weakened economic conditions also may adversely affect the collectability of our trade receivables. For example, our accounts receivable are primarily from purchasers of our oil, natural gas and NGL production and other exploration and production companies that own working interests in the properties that we operate. This industry concentration could adversely impact our overall credit risk because our customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices and other conditions. Further, a credit crisis and turmoil in the financial markets in the future could cause our commodity derivative instruments to be ineffective in the event a counterparty was unable to perform its obligations or sought bankruptcy protection.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, take advantage of business opportunities, respond to competitive pressures or refinance our debt obligations as they come due, any of which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our substantial indebtedness could adversely affect our financial condition.

We have a significant amount of indebtedness. As of December 31, 2011, our total long-term debt was \$331 million, and we had unused commitments of approximately \$92.4 million under our bank credit facility (after deducting \$1.6 million of outstanding letters of credit). As of March 20, 2012, our total long-term debt was approximately \$384 million, and we had unused commitments of approximately \$188 million under our bank credit facility (after deducting \$1.6 million of outstanding letters of credit).

Subject to the limits contained in the indenture governing the Senior Notes and our other debt instruments, we may be able to incur substantial additional debt from time to time to finance working capital, capital expenditures, investments or acquisitions or for other purposes. If we do so, the risks related to our high level of debt could intensify. Specifically, our high level of debt could have important consequences, including the following:

- making it more difficult for us to satisfy our obligations with respect to the Senior Notes and our other debt instruments;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, investments, acquisitions or other general corporate requirements;
- requiring a substantial portion of our cash flows to be dedicated to debt service payments instead of other purposes, thereby reducing the amount of cash flows available for working capital, capital expenditures, investments, acquisitions and other general corporate purposes;
- increasing our vulnerability to general adverse economic and industry conditions;
- exposing us to the risk of increased interest rates as certain of our borrowings are at variable rates of interest;
- limiting our flexibility in planning for and reacting to changes in the oil and gas industry;
- placing us at a disadvantage compared to other, less leveraged competitors; and
- increasing our cost of borrowing.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance and, as a result, our ability to generate cash flow from operating activities and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control. If we do not generate enough cash flow from operating activities to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- refinancing or restructuring our debt.

If for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at

that time to declare all outstanding indebtedness to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on the Senior Notes. If amounts outstanding under our bank credit facility or the Senior Notes were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders.

The indenture governing the Senior Notes and our bank credit facility contain substantial operating and financial restrictions that may restrict our business and financing activities and could have a material adverse effect on our business, financial condition, cash flows and results of operations.

The indenture governing the Senior Notes and the credit agreement governing our bank credit facility contain, and any future indebtedness that we incur may contain, a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;
- pay distributions on, redeem or repurchase our common stock or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create or incur certain liens;
- make certain acquisitions and investments;
- redeem or prepay other debt;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; and
- engage in certain business activities.

In addition, the credit agreement governing our bank credit facility provides that we will not permit our ratio of total debt outstanding to consolidated EBITDA (as adjusted for non-cash charges) for a trailing 12-month period to be greater than 4.00 to 1.00.

As a result of these covenants and restrictions, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs. Our ability to comply with these covenants and restrictions in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired.

The credit agreement governing our bank credit facility also limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion taking into account the estimated value of our oil and gas properties. Outstanding borrowings in excess of the borrowing base must be repaid. If we do not have sufficient funds on hand for repayment, we may be required to seek

a waiver or amendment from our lenders, refinance our bank credit facility or sell assets, debt or common stock. We may not be able to obtain such financing or complete such transactions on terms acceptable to us, or at all. Failure to make the required repayment could result in an event of default under the credit agreement governing our bank credit facility.

A failure to comply with the requirements of the credit agreement governing our bank credit facility or any future indebtedness could result in an event of default under the credit agreement governing our bank credit facility or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition, cash flows and results of operations. If an event of default under the credit agreement governing our bank credit facility occurs and remains uncured, the lenders thereunder:

- would not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings; or
- may prevent us from making debt service payments under our other agreements.

A payment default or an acceleration under the credit agreement governing our bank credit facility could result in an event of default and an acceleration under the indenture for the Senior Notes.

If the indebtedness under the Senior Notes were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. In addition, our obligations under the credit agreement governing our bank credit facility are secured by substantially all of our assets, and if we are unable to repay our outstanding indebtedness under our bank credit facility, the lenders could seek to foreclose on our assets. Please see Part II, “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Our use of hedging transactions could result in financial losses or reduce our income.

To reduce our exposure to fluctuations in oil, natural gas and NGL prices, we enter into derivative instruments (or hedging agreements) for a portion of our oil, natural gas and NGL production. We expect that our commodity hedging agreements will be limited in duration, usually for periods of two years or less; however, in conjunction with acquisitions, we may enter into or acquire hedges for longer periods. Our hedging transactions expose us to certain risks and financial losses, including, among others, the risk that:

- we may be limited in receiving the full benefit of increases in oil, natural gas and NGL prices as a result of these transactions;
- we may hedge too much or too little production, depending on how oil, natural gas and NGL prices fluctuate in the future;
- there is a change to the expected differential between the underlying price and the actual price received; and
- a counterparty to a hedging arrangement may default on its obligations to us.

Our hedging transactions will impact our earnings in various ways. Due to the volatility of oil, natural gas and NGL prices, we may be required to recognize mark-to-market gains and losses on derivative instruments, as the estimated fair value of our commodity derivative instruments is subject to significant fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period-to-period estimates and will be a function of the actual price of the commodities on the settlement date of the derivative instrument. We expect that commodity prices will

continue to fluctuate in the future, and, as a result, our periodic financial results will be subject to fluctuations related to our derivative instruments.

The implementation of financial reform legislation and regulations could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

To reduce our exposure to fluctuations in oil, natural gas and NGL prices, we enter into additional derivative instruments (or hedging agreements) for a portion of our oil, natural gas and NGL production. Over-the-counter derivatives have been the subject of recent legislative and regulatory initiatives. In the United States, comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), was adopted in 2010. This legislation, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including businesses like ours, that participate in that market. The Dodd-Frank Act requires the U.S. Commodity Futures Trading Commission (the “CFTC”) and the SEC to promulgate rules and regulations implementing the new legislation. In December 2011, the CFTC extended temporary exemptive relief from certain swap regulation provisions of the legislation until July 16, 2012. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions are exempt from these position limits. It is not possible at this time to predict when the CFTC will make these regulations effective. In Canada, securities regulatory authorities have since November 2010 published a series of consultation papers on over-the-counter derivatives regulation, which present high-level proposals and recommendations on derivatives market regulation that are similar, in certain respects, to matters provided for under the Dodd-Frank Act. New regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivatives activities, although the application of those provisions to us is uncertain at this time, and may also require the counterparties to our derivative instruments to spin-off some of their derivatives activities to a separate entity, which may not be as creditworthy as such counterparty. Such legislative and regulatory initiatives could significantly increase the cost of derivatives contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure any derivatives contracts and increase our exposure to less creditworthy counterparties. If we limit our use of derivatives as a result of any such legislative and regulatory initiatives, 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, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil, natural gas and NGL prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and NGLs. Our revenues could, therefore, be adversely affected if a consequence of any new legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Lower oil, natural gas and NGL prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values.

We use the full cost method of accounting to report our oil and gas operations. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and gas properties may not exceed a “ceiling limit,” which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a “ceiling test write-down.” Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test

write-down would not impact cash flow from operating activities, but it would reduce our stockholders' equity. See Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies, Estimates, Judgments and Assumptions—*Full Cost Method of Accounting*" for further details.

Investments in unproved properties, including capitalized interest costs, are also assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties and geographic and geologic data obtained relating to the properties. The amount of impairment assessed, if any, is added to the costs to be amortized. If an impairment of unproved properties results in a reclassification to proved oil and gas properties, the amount by which the ceiling limit exceeds the net capitalized costs of proved oil and gas properties would be reduced.

The risk that we will be required to write-down the carrying value of our oil and gas properties, our unproved properties or goodwill increases when oil, natural gas and NGL prices are low. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. For example, we recorded a non-cash ceiling test write-down of approximately \$251.0 million in the first quarter of 2009. This write-down was reflected as a charge to net earnings. Additional ceiling test write-downs may be required if oil, natural gas and NGL prices decline further or the current decline in natural gas prices continues, unproved property values decrease, estimated proved reserve volumes are revised downward or costs incurred in exploration, development or acquisition activities exceed the discounted future net cash flows from the additional reserves, if any. Based on the recent decline of natural gas prices, there is an increased risk that we may be required to record a non-cash ceiling test write-down in the future.

Our proved reserves are estimates and depend on many assumptions. Any material inaccuracies in these assumptions could cause the quantity and value of our oil and natural gas reserves, and our revenue, profitability and cash flow, to be materially different from our estimates.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

In connection with the preparation of our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and net present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our estimated proved reserves is the current market value of our estimated proved reserves. We are required to base the estimated discounted future net cash flows from our estimated proved reserves on 12-month average prices and costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

We have based our estimated discounted future net revenues from our estimated proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding 12 months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil, natural gas and NGLs;
- actual cost and timing of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this Form 10-K.

Our failure to replace our reserves could result in a material decline in our reserves and production, which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

In general, our proved reserves decline when oil and natural gas is produced, unless we are able to conduct successful exploitation, exploration and development activities or acquire additional properties containing proved reserves, or both. Our future performance, therefore, is dependent upon our ability to find, develop and acquire additional oil and natural gas reserves that are economically recoverable. Exploring for, developing or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop or acquire additional reserves or may not be able to make the necessary capital investments if our cash provided by operating activities decline or external sources of capital become limited or unavailable. We cannot assure you that our future exploitation, exploration, development and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. See “—We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy” for a discussion of the impact of financial market conditions on our access to financing.

Our actual production could differ materially from our forecasts.

From time to time, we provide forecasts of expected quantities of future oil and gas production. These forecasts are based on a number of estimates, including expectations of production from existing wells. In addition, our forecasts assume that none of the risks associated with our oil and gas operations summarized in this Form 10-K occur, such as facility or equipment malfunctions, adverse weather effects or significant declines in commodity prices or material increases in costs, which could make certain production uneconomical.

As part of our ongoing operations, we plan to explore in new or emerging plays. As a result, our drilling in these areas is subject to greater risk and uncertainty.

We sometimes explore in new or emerging plays. These activities are more uncertain than drilling in areas that are developed and have established production. Because emerging plays and new formations have limited or no production history, we are less able to use past drilling results to help predict future results. The lack of historical information may result in our being unable to fully execute our expected drilling programs in these areas, or the return on investment in these areas may turn out to not be as attractive as anticipated. We cannot assure you that our future drilling activities in the Utica Shale in Quebec, the Liard Basin in the Northwest Territories or other emerging plays will be successful or, if successful, will achieve the potential resource levels that we currently anticipate based on the drilling activities that have been completed or will achieve the anticipated economic returns based on our current cost models.

Exploration and drilling activities involve substantial risks and may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The seismic data and other technologies that we use when drilling wells do not allow us to conclusively determine prior to drilling a well whether oil, natural gas or NGLs are present or can be produced economically. As a result, we may drill new wells or participate in new wells that are dry wells or are productive but not commercially productive, and, as a result, we may not recover all or any portion of our investment in the wells we drill or in which we participate.

The costs and expenses of drilling, completing and operating wells are often uncertain. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause our drilling costs to be significantly higher than expected or cause our drilling activities to be unsuccessful or result in the total loss of our investment. Also, our development and exploration operations may be shortened, delayed or canceled or we may incur significant expenditures that are not provided for in our capital budget as a result of a variety of factors, many of which are beyond our control, including, among others:

- unexpected drilling conditions;
- geological irregularities or pressure in formations;
- mechanical difficulties and equipment failures or accidents;
- increases in the costs of, or shortages or delays in the availability of, drilling rigs and related equipment;
- shortages in labor;
- adverse weather conditions;
- compliance with environmental and other governmental requirements;
- fires, explosions, blow-outs or cratering; and
- restricted access to land necessary for drilling or laying pipelines.

Drilling activities are subject to many risks, including well blow-outs, cratering, explosions, pipe failures, fires, uncontrollable flows of oil, natural gas, brine or well fluids, other environmental hazards and risks outside of our control, including the factors described above and other risks associated with conducting drilling activities. Among other things, these risks include the risk of natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases and extensive abandonment, reclamation and remediation costs, any of which could result in substantial losses, personal injuries or loss of life, severe

damage to or destruction of property, natural resources and equipment, extensive pollution or other environmental damage, clean-up responsibilities, regulatory investigations, administrative, civil and criminal penalties and injunctions resulting in the suspension of our operations. If any of these risks occur, we could sustain substantial losses.

Drilling locations that we decide to drill may not yield oil, natural gas or NGLs in commercially viable quantities.

We describe drilling locations that are not proved undeveloped drilling locations, and our plans to explore those drilling locations in this Form 10-K. These non-proved drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively, prior to drilling, whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil, natural gas or NGLs exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our other identified drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. In summary, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our drilling locations are scheduled to be drilled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the significant amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management has identified and scheduled drilling locations as an estimate of our future multi-year drilling activities on our existing acreage. As of December 31, 2011, we had 151 gross (125 net) drilling locations with proved undeveloped reserves attributed to them. All of our drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil, natural gas and NGL prices, costs and drilling results. Because of these uncertainties, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. If natural gas prices remain depressed for an extended period of time, it might not be economic for us to drill sufficient wells in order to hold acreage, which could result in the expiry of a portion of our acreage, which could have a material adverse effect on our business, financial condition, cash flows and results of operation.

Unless production is established within the spacing units covering the undeveloped acres on which some of our drilling locations are identified, the leases for such acreage may expire. As of December 31, 2011, we had leases representing 64,211 net acres expiring in 2012, 10,127 net acres expiring in 2013 and 47,524 net acres expiring in 2014, representing 8%, 1% and 6% of our total net acreage, respectively.

Competition within our industry is intense and may have a material adverse effect on our business, financial condition, cash flows and results of operations.

We operate in a highly competitive environment. We compete with major and independent oil and gas companies in acquiring desirable oil and gas properties and in obtaining the equipment and labor required to develop and operate such properties. We also compete with major and independent oil and gas companies in the marketing and sale of oil, natural gas and NGLs. Many of these competitors are larger, including some of the fully integrated energy companies, and have financial, staff and other resources substantially greater than ours. As a result, these companies may have greater access to capital and may be able to pay more for development prospects and producing properties, or evaluate and bid for a greater number of properties and prospects, than our financial and staffing resources permit. Also, from time to time, we have to compete with financial investors in the property acquisition market, including private equity sponsors with more funds and access to additional liquidity. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and evaluate properties, available funds and internal standards for minimum projected return on investment. In addition, while costs for equipment, services and labor in the industry, as well as the cost of properties available for acquisition, tend to fluctuate with oil, natural gas and NGL prices, these costs often do not decrease proportionately to, or their decreases lag behind, decreases in commodity prices. This disconnect can negatively impact our cash flows and may put us at a competitive disadvantage with respect to companies that have greater financial and operational resources. In addition, oil and gas producers are increasingly facing competition from providers of non-fossil energy, and government policy may favor those competitors in the future. Many of these competitors have financial and other resources substantially greater than ours. We can give no assurance that we will be able to compete effectively in the future and that our business, financial condition, cash flows and results of operations will not suffer as a result.

Our business, financial condition, cash flows and results of operations may be adversely affected by foreign currency fluctuations and economic and political developments.

Currently, all of our oil and gas properties and operations are located in Canada. As a result, we are exposed to the risks associated with operating as a foreign company in Canada, including political and economic developments, royalty and tax increases, changes in laws or policies affecting our exploration and development activities and currency exchange risks, as well as changes in the policies of Canada affecting trade, taxation, investment and the environment.

Our operations are impacted by the regulatory requirements in the provinces and territories in which our operations are located, and our project economics are influenced by the differing royalty regimes in each of these locations. Any adverse regulatory developments relating to the royalty regimes applicable to our operations or the laws or policies affecting our exploration and development activities could have a material adverse effect on our business, financial condition, cash flows and results of operations. See “—Our oil and gas operations are subject to various environmental and other governmental laws and regulations that materially affect our operations” below and “—New laws or regulatory requirements relating to hydraulic fracturing could make it more difficult or costly for us to perform fracturing of producing formations and could have an adverse effect on our ability to produce oil and gas from new wells” below and “Business—Industry Regulation,” “Business—Royalties,” “Business—Land Tenure” and “Business—Environmental Regulation—Climate Change Regulation,” in Part I, “Item I. Business” for more detail on the Canadian regulatory framework.

Effective October 1, 2011, Lone Pine changed its functional currency and reporting currency from the U.S. dollar to the Canadian dollar. Following the changes in functional currency and reporting currency, we will be subject to foreign currency exchange rate risk relating to the Senior Notes, certain of our derivative instruments and our delivery commitment of approximately 21,000 MMBtu/d of natural gas under a long-term sales contract expiring in 2014.

Our oil and gas operations are subject to various environmental and other governmental laws and regulations that materially affect our operations.

Our oil and gas operations are subject to various Canadian federal, provincial, territorial and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure, the exploration and development of hydrocarbon resources and the production, handling, storage, transportation and disposal of oil and gas, by-products from oil and gas and other substances and materials produced or used in connection with oil and gas operations. Federal authorities do not regulate the price of oil and gas in export trade. However, Canadian law regulates the quantities of oil, natural gas and NGLs that may be removed from the provinces and exported from Canada in certain circumstances. Significant regulatory requirements also exist related to licensing for drilling and completion of wells, the method and ability to produce from wells, surface usage, transportation of production and conservation matters. In addition, the provinces and territories in which we operate have laws and regulations governing land tenure, royalties, production rates and taxes, environmental protection and other matters under their respective jurisdiction. Compliance with these laws and regulations can affect the location or size of leases and facilities, prohibit or limit the extent to which exploration and development may be allowed and require proper abandonment of wells and restoration of properties when production ceases. Failure to comply with laws and regulations in effect from time to time may result in the assessment of administrative, civil or criminal penalties, imposition of remedial obligations, loss or cancellation of governmental or regulatory approvals and issuance of injunctions or similar orders that could delay, limit or prohibit certain of our operations, any of which could have a material adverse effect on our business, financial condition, cash flows and results of operations. We are subject to stringent rules concerning the release into the environment of substances in connection with drilling and production activities (including fracture stimulation operations), and a significant spill or other discharge from one of our facilities could have a material adverse effect on our business, financial condition, cash flows and results of operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations. We may not be able to recover some or any of these costs from insurance.

Most oil and natural gas resources located in the Canadian provinces and territories in which we operate are owned by the government, and are explored for and produced pursuant to leases, licenses, permits and regulations issued by that government or its agencies. Any governmental action to unilaterally cancel, limit or otherwise adversely change any such lease, license, permit or regulation pursuant to which we explore for or produce oil or natural gas, which action could include termination of our property interests or other rights in affected lands, with or without compensation, could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our operations are, and will continue to be, affected to varying degrees by laws and regulations regarding environmental protection, which may be changed to impose higher standards and potentially more costly obligations on us. Future environmental laws or regulations or approvals or processes required thereunder, the direct and indirect costs of complying with such laws, regulations, approvals or processes, and the consequences of any non-compliance, may adversely affect our business, financial condition, cash flows and results of operations. We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. See Part I, “Item 1. Business—Environmental Regulation.” Canadian federal, provincial and territorial governments are continuing to assess and develop GHG emission reduction strategies. The direct and indirect costs of complying with any GHG emission reduction requirements arising from the implementation of any such strategies or any related laws or regulations imposed either federally, provincially, territorially or locally may adversely affect our business, financial condition, cash flows and results of operations. See Part I, “Item 1. Business—Environmental Regulation—*Climate Change Regulation.*”

New laws or regulatory requirements relating to hydraulic fracturing could make it more difficult or costly for us to perform fracturing of producing formations and could have an adverse effect on our ability to produce oil and gas from new wells.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons. The process involves the injection of fluid, sand and chemicals under pressure into a hydrocarbon-bearing geological formation to fracture the surrounding rock and stimulate production. Some concern has been expressed over the potential environmental impact of hydraulic fracturing operations, including with respect to the qualitative and quantitative effect on water resources, as large quantities of water are used and injected fluids either remain underground or flow back to the surface to be collected, treated and disposed of. Governmental and regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. In Quebec, the provincial government, acting upon recommendations of BAPE, which had been requested to review environmental and health and safety issues concerning the development of the shale gas industry in Quebec in connection with the government's consideration of a new oil and gas regulatory regime for the province, has commissioned a SEA of shale gas drilling, pending which hydraulic fracturing will only be allowed if required for SEA purposes. A committee was appointed in May 2011 to conduct the SEA, which is expected to take 18 to 30 months to complete, and is to report annually, with the first report due in May 2012. On June 13, 2011, Quebec enacted legislation that prohibits oil and gas activities in the St. Lawrence River upstream of Anticosti Island and on the islands situated in that part of the river and revokes, without compensation, oil and gas rights previously issued for that area. We held exploration licenses to 33,460 net acres under the St. Lawrence River that were revoked by this legislation and are considering available alternatives with respect to the Quebec government's action. The revoked acreage consists entirely of undeveloped lands. No reserves are attributed to our Quebec properties. In British Columbia, public disclosure of hydraulic fracturing fluid ingredients became mandatory as of January 1, 2012, and the provincial government established an online registry providing public access to information on fractured well locations and hydraulic fracturing fluid ingredients. At a media briefing held in late February 2012 regarding current regulations governing hydraulic fracturing operations in Alberta, representatives of the ERCB were reported to have advised that the ERCB expects to implement rules requiring public disclosure of hydraulic fracturing fluid ingredients before the end of 2012. See Part I, "Item 1. Business—Environmental Regulation."

Regulatory initiatives relating to hydraulic fracturing have also commenced or been announced in the United States, where some states have adopted or are considering the adoption of regulations that could restrict hydraulic fracturing in certain circumstances and require disclosure of chemicals used in the fracturing process, and the U.S. Environmental Protection Agency and a committee of the U.S. House of Representatives have both initiated reviews of hydraulic fracturing practices. If new laws or regulatory requirements that prohibit or otherwise significantly restrict hydraulic fracturing are adopted in any jurisdiction in which we operate, whether as a consequence of environmental concerns or otherwise, it may become more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, additional permitting, disclosure or other regulatory obligations may make it more difficult for us to complete oil and natural gas wells and cause permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil, natural gas and NGLs that we are ultimately able to produce from our reserves.

Aboriginal peoples have claimed aboriginal title and rights in portions of Canada.

Aboriginal peoples have claimed aboriginal title and rights in portions of Canada. We are not aware that any claims have been made against us in respect of our properties and assets; however, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition, cash flows and results of operations. Our operations may be delayed or interrupted to the extent that they are deemed to encroach on the traditional rights of aboriginal peoples to hunt, trap or

otherwise have access to natural resources. For example, in 2010, we encountered certain infrastructure constraints in our Ojay field in British Columbia, due in part to a several-month delay in permitting required for gathering pipelines installed in the field, while an aboriginal people considered the installation's potential impact on their traditional land use. We may face similar delays and interruptions in the future.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control.

The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities, as well as delays in the construction of new infrastructure facilities, could harm our business. We deliver a majority of our oil, natural gas and NGLs through gathering facilities and downstream infrastructure that we either do not own or do not operate. As a result, we are subject to the risk that these facilities may be temporarily unavailable due to mechanical reasons or market conditions, or may not be available to us in the future. For example, we experienced shut-in production due to infrastructure constraints in our Ojay field in British Columbia in 2010, due in part to a several-month delay in permitting required for gathering pipelines recently installed in the field, while an aboriginal people considered the installation's potential impact on their traditional land use. If we experience interruptions or loss of pipelines or access to gathering systems that impact a substantial amount of our production, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.

We may not be insured against all of the operating risks to which our business is exposed.

The exploration, development and production of oil, natural gas and NGLs involve operating risks. These risks include the risk of fire, explosions, blow-outs, pipe failure, damaged drilling and oil field equipment, abnormally pressured formations, weather-related issues and environmental hazards. Environmental hazards include oil spills, natural gas leaks, pipeline ruptures or discharges of toxic gases and extensive abandonment, reclamation and remediation costs. If any of these industry-operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Consistent with industry practice, we maintain insurance against some, but not all, of the risks described above. Generally, pollution-related environmental risks are not fully insurable. We do not insure against business interruption. We cannot assure that our insurance will be adequate to fully cover our losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

We have incurred, and will in the future incur, increased legal, accounting and other costs as a result of being a public company.

Prior to our IPO, as a subsidiary of a public company, we were not directly responsible for the corporate governance and financial reporting practices, policies and disclosure required of a public company. As a public company, we have incurred, and will continue to incur in the future, significant legal, accounting and other expenses that we did not directly incur in the past. In addition, the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"), the Dodd-Frank Act and applicable Canadian securities laws, as well as new rules implemented by the SEC, Canadian securities regulators and the New York Stock Exchange (the "NYSE"), require or may require changes in corporate governance practices of public companies. We expect these new rules and regulations to increase our legal and financial compliance costs and to make some activities more time-consuming and costly. All of the

foregoing may cause our costs to be higher than the historical costs associated with these areas reflected in our financial statements.

Our results as a separate, stand-alone public company could be materially different from those portrayed in our historical financial results.

Certain of the historical financial information included in this Form 10-K has been derived from the consolidated financial statements of LPR Canada before it became a subsidiary of Lone Pine Resources Inc. The historical costs and expenses reflected in LPR Canada's consolidated financial statements for the periods prior to our IPO include a management fee intended to reimburse Forest for certain corporate functions provided by Forest on our behalf, including, among other things, executive oversight, insurance and risk management, treasury, information technology, legal, accounting, tax, marketing, corporate engineering and human resources services. The management fee was based on what Forest considered to be reasonable reflections of the historical utilization levels of these services required in support of our business. In addition, a portion of the interest costs reflected in LPR Canada's consolidated financial statements was associated with a note payable to and advances from Forest, which provided for interest rates that may not have been comparable with the rates we would have negotiated with a third party. Other significant changes may occur in our cost structure, management, financing and business operations as a result of operating as a separate, stand-alone public company. For additional information, see Part II, "Item 6. Selected Financial Data" and Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and the notes thereto included elsewhere in this Form 10-K.

If we are unable to satisfy the requirements of Section 404 of the Sarbanes-Oxley Act, or our internal controls over financial reporting are not effective, the reliability of our financial statements may be questioned, and our share price may suffer.

Section 404 of the Sarbanes-Oxley Act requires any company subject to the reporting requirements of the U.S. securities laws to perform a comprehensive evaluation of its and its subsidiaries' internal controls over financial reporting. Similar requirements apply to reporting issuers under Canadian securities laws. To comply with these requirements, we are required to document and test our internal control procedures, our management is required to assess and issue a report concerning our internal controls over financial reporting, and, under the Sarbanes-Oxley Act, our independent auditors are required to issue an opinion on management's assessment and the effectiveness of our internal controls over financial reporting. Our compliance with Section 404 of the Sarbanes-Oxley Act will first be reported on in connection with the filing of our Annual Report on Form 10-K for the fiscal year ending December 31, 2012. The rules governing the standards that must be met for management to assess our internal controls over financial reporting are complex and require significant documentation, testing and possible remediation. During the course of its testing, our management may identify material weaknesses or significant deficiencies, which may not be remedied in time to meet the deadline imposed by the SEC rules implementing Section 404. If our management cannot favorably assess the effectiveness of our internal controls over financial reporting, or our auditors identify material weaknesses in our internal controls, investor confidence in our financial results may weaken, and our share price may suffer.

Risks Related to Our Separation from Forest

Our separation agreements with Forest require us to assume the past, present and future liabilities related to our business and may be less favorable to us than if they had been negotiated with unaffiliated third parties.

We entered into agreements with Forest related to the separation of our business operations from Forest, including a separation and distribution agreement, a tax sharing agreement, a transition services agreement, an employee matters agreement and a registration rights agreement. We negotiated our

separation agreements with Forest as a wholly-owned subsidiary of Forest and entered into these agreements immediately prior to the completion of our IPO. If these agreements had been negotiated with unaffiliated third parties, they might have been more favorable to us. Pursuant to these agreements, we have agreed to indemnify Forest for, among other matters, all past, present and future liabilities (other than tax liabilities, which will be governed by our tax sharing agreement with Forest) related to our business, and we have assumed these liabilities under the separation agreements. Such liabilities include unknown liabilities that could be significant. The allocation of liabilities between Forest and us may not reflect the allocation that would have been reached between two unaffiliated parties.

The separation agreements may limit our ability to obtain additional financing or make acquisitions and may require us to pay significant tax liabilities.

We may engage, or desire to engage, in future financings or acquisitions. However, because the separation agreements are designed to preserve the tax-free status of the spin-off, we have agreed to certain restrictions in those agreements that may severely limit our ability to effect future financings or acquisitions. For a period of two years after the date of the spin-off, we have agreed to be subject to certain restrictions under which we will be permitted to take certain actions only if Forest consents to the taking of such action or if we obtain and provide to Forest a private letter ruling from the Internal Revenue Service (“IRS”) and/or an opinion from a law firm or accounting firm, in either case acceptable to Forest in its sole discretion, to the effect that such action would not jeopardize the tax-free status of the contribution and the spin-off. Thus, for that two-year period, these covenants will restrict our ability to sell assets outside the ordinary course of business, to issue or sell our common stock or other securities (including securities convertible into our common stock but excluding certain compensation arrangements) or to enter into any other corporate transaction that would cause us to undergo either a 50% or greater change in the ownership of our voting stock or a 50% or greater change in the ownership (measured by value) of all classes of our stock. We are also required to indemnify Forest against certain tax-related liabilities incurred by Forest relating to the spin-off, to the extent caused by us. These liabilities include the substantial tax-related liability (calculated without regard to any net operating loss or other tax attribute of Forest) that would result if the spin-off failed to qualify as a tax-free transaction.

Finally, we are required to indemnify Forest against any additional Canadian tax-related liabilities incurred by Forest with respect to the contribution to us of its ownership interests in, and certain indebtedness of, LPR Canada and the transactions completed in conjunction with such contribution. As a result of these transactions, Forest determined that it was required to pay Canadian taxes in an amount consistent with an opinion of Forest’s outside tax advisor and paid such taxes. To the extent that the Canadian tax authorities disagree with Forest’s determination of the amount of Canadian taxes due and attempt to assess and recover additional Canadian taxes from Forest, we will be required to indemnify, and if necessary reimburse, Forest with respect to such additional taxes, costs incurred in contesting such additional taxes and any penalties and interest associated with such additional taxes. We believe that our maximum monetary exposure relating to this indemnity is approximately \$47 million, plus interest. The triggering of this indemnity could have a material adverse impact on our liquidity and our ability to execute our business plan.

We will not have complete control over our tax decisions that relate to periods prior to the spin-off and could be liable for income taxes owed by Forest.

We or one or more of our U.S. subsidiaries may be included in the combined, consolidated or unitary tax returns of Forest or one or more of its subsidiaries for U.S. federal, state or local income tax purposes for periods prior to the spin-off. Under the tax sharing agreement, we generally will pay to, or receive from, Forest the amount of U.S. federal, state and local income taxes that we would be

required to pay to, or entitled to receive from, the relevant taxing authorities if we and our U.S. subsidiaries filed combined, consolidated or unitary income tax returns and were not included in the combined, consolidated or unitary tax returns of Forest or its subsidiaries. In addition, by virtue of the tax sharing agreement, Forest will effectively control all of our U.S. tax decisions in connection with any combined, consolidated or unitary income tax returns in which we or any of our subsidiaries are included. The tax sharing agreement provides that Forest will have sole authority to respond to and conduct all tax proceedings (including tax audits) relating to us, to file all tax returns on our behalf and to determine the amount of our liability to, or entitlement to payment from, Forest in connection with any combined, consolidated or unitary income tax returns in which we (or any of our subsidiaries) are included. This arrangement may result in conflicts of interest between Forest and us. For example, under the tax sharing agreement, Forest will be able to choose to contest, compromise or settle any adjustment or deficiency proposed by the relevant taxing authority in a manner that may be beneficial to Forest and detrimental to us. Moreover, notwithstanding the tax sharing agreement, U.S. federal law provides that each member of a consolidated group is liable for the group's entire tax obligation. Thus, to the extent Forest or other members of the group fail to make any U.S. federal income tax payments required by law for periods during which we were a member of such group, we could be liable for the shortfall. Similar principles may apply for foreign, state or local income tax purposes where we file combined, consolidated or unitary returns with Forest or its subsidiaries for federal, foreign, state or local income tax purposes.

If there is a determination that the spin-off is taxable for U.S. federal income tax purposes because the facts, assumptions, representations or undertakings underlying the IRS private letter ruling or tax opinion are incorrect or for any other reason, then Forest and its shareholders could incur significant income tax liabilities, and we could incur significant liabilities.

Our IPO and the spin-off were conditioned upon, among other things, Forest's receipt of a private letter ruling from the IRS, and/or an opinion of its outside tax advisor, in either case reasonably acceptable to the Forest board of directors, to the effect that the contribution by Forest of its direct and indirect ownership interest in LPR Canada to us and the distribution by Forest of the shares of our common stock held by Forest after the offering should qualify for U.S. federal income tax purposes as a tax-free transaction under Sections 355 and 368(a)(1)(D) of the U.S. Internal Revenue Code of 1986, as amended (the "Code"). Forest obtained an opinion of its outside tax advisor that was acceptable to the Forest board of directors to the effect that the contribution by Forest of its direct and indirect ownership interest in LPR Canada to us and the distribution by Forest of the shares of our common stock held by Forest after our IPO should qualify for U.S. federal income tax purposes as a tax-free transaction under Sections 355 and 368(a)(1)(D) of the Code, which opinion satisfied the related condition to our IPO and the spin-off. Forest also received a private letter ruling from the IRS. The opinion and the ruling rely on certain facts, assumptions, representations and undertakings from Forest and us regarding the past and future conduct of the companies' respective businesses and other matters. If any of these facts, assumptions, representations or undertakings are incorrect or not otherwise satisfied, Forest and its shareholders may not be able to rely on the private letter ruling or the opinion of its tax advisor and could be subject to significant tax liabilities. Notwithstanding the private letter ruling or the opinion of Forest's tax advisor, the IRS could determine upon audit that the spin-off is taxable if it determines that any of these facts, assumptions, representations or undertakings are not correct or have been violated or if it disagrees with the conclusions in the opinion that are not covered by the private letter ruling, or for other reasons, including as a result of certain significant changes in the stock ownership of Forest or us after the spin-off. If the spin-off is determined to be taxable for U.S. federal income tax purposes, Forest and its shareholders could incur significant income tax liabilities, and we could incur significant liabilities.

Third parties may seek to hold us responsible for liabilities of Forest that we did not assume in our agreements.

Third parties may seek to hold us responsible for retained liabilities of Forest. Under the separation agreements, Forest has agreed to indemnify us for claims and losses relating to these retained liabilities. However, if those liabilities are significant and we are ultimately held liable for them, we cannot assure you that we will be able to recover the full amount of our losses from Forest.

Our prior relationship with Forest exposes us to risks attributable to businesses of Forest.

Forest is obligated to indemnify us for losses that a party may seek to impose upon us or our affiliates for liabilities relating to the business of Forest that are incurred through a breach of the separation agreements or any ancillary agreement by Forest or its affiliates other than us, if losses are attributable to Forest in connection with our IPO or were not expressly assumed by us under the separation agreements. Any claims made against us that are properly attributable to Forest in accordance with these arrangements would require us to exercise our rights under the separation agreements to obtain payment from Forest. We are exposed to the risk that, in these circumstances, Forest cannot, or will not, make the required payment.

We may have potential business conflicts of interest with Forest regarding our past and ongoing relationships, and the resolution of these conflicts may not be favorable to us.

Conflicts of interest may arise between Forest and us in a number of areas relating to our past and ongoing relationships, including:

- labor, tax, employee benefit, indemnification and other matters arising under the separation agreements;
- employee recruiting and retention; and
- business opportunities that may be attractive to both Forest and us.

We may not be able to resolve any potential conflicts, and, even if we do so, the resolution may not be favorable to us.

For two years after the completion of our IPO, (1) Forest has agreed not to acquire any oil and gas properties in Canada, unless such oil and gas properties in Canada constitute less than a majority of the assets included in a particular business opportunity, and (2) we have agreed not to acquire any oil and gas properties in the United States, unless such oil and gas properties in the United States constitute less than a majority of the assets included in a particular business opportunity. However, during this two-year period, if Forest obtains our prior consent with respect to a defined area in Canada, it may engage in activities in that area, and, similarly, if we obtain Forest's prior consent with respect to a defined area in the United States, we may engage in activities in that area.

For two years after the completion of our IPO, neither we nor Forest will be permitted to solicit each other's active employees for employment without the other's consent.

Pursuant to the terms of our certificate of incorporation, Forest is not required to offer corporate opportunities to us, and one of our directors is permitted to offer certain corporate opportunities to Forest before us.

Our certificate of incorporation provides that, until both (1) Forest and its subsidiaries no longer beneficially own 50% or more of the voting power of all then outstanding shares of our capital stock

generally entitled to vote in the election of our directors and (2) no person who is a director or officer of Forest or of a subsidiary of Forest is also a director or officer of ours:

- Forest is free to compete with us in any activity or line of business, except as provided in the separation and distribution agreement or other written agreement between us and Forest;
- we do not have any interest or expectancy in any business opportunity, transaction or other matter in which Forest engages or seeks to engage merely because we engage in the same or similar lines of business;
- to the fullest extent permitted by law, Forest will have no duty to communicate its knowledge of, or offer, any potential business opportunity, transaction or other matter to us, and Forest is free to pursue or acquire such business opportunity, transaction or other matter for itself or direct the business opportunity, transaction or other matter to its affiliates and Forest will not, to the fullest extent permitted by law, be deemed to have (1) breached or acted in a manner inconsistent with or opposed to its fiduciary or other duties to us regarding the business opportunity, transaction or other matter or (2) acted in bad faith or in a manner inconsistent with the best interests of our company or our stockholders; and
- to the fullest extent permitted by law, if any director or officer of Forest who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that business opportunity to us and will be permitted to communicate or offer that business opportunity to Forest (or its affiliates), and that director or officer will not, to the fullest extent permitted by law, be deemed to have (1) breached or acted in a manner inconsistent with or opposed to his or her fiduciary or other duties to us regarding the business opportunity, transaction or other matter or (2) acted in bad faith or in a manner inconsistent with the best interests of our company or our stockholders.

As a result of the Distribution, Forest has no remaining ownership interest in us; however, the chairman of our Board of Directors is also an independent director of Forest. As a result, Forest may gain the benefit of corporate opportunities that are presented to this director.

Risks Relating to Ownership of Our Common Stock

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

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

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

We do not anticipate paying any dividends on our common stock in the foreseeable future. Any declaration and payment of future dividends to holders of our common stock may be limited by the provisions of the Delaware General Corporation Law, certain restrictive covenants in our bank credit

facility and certain restrictive covenants in the indenture governing the Senior Notes. The future payment of dividends will be at the sole discretion of our Board of Directors and will depend on many factors, including our earnings, capital requirements, financial condition and other considerations that our Board of Directors deems relevant. As a result, to receive any income or realize a return on your investment, you will need to sell your shares of common stock. You may not be able to sell your shares of common stock at or above the price you paid for them.

Our certificate of incorporation, bylaws, stockholder rights plan and Delaware state law contain provisions that may have the effect of delaying or preventing a change in control of our company.

Our certificate of incorporation authorizes our Board of Directors to issue preferred stock and to determine the designations, powers, preferences and relative, participating, optional or other special rights, if any, and the qualifications, limitations or restrictions of our preferred stock, including the number of shares, in any series, without any further vote or action by the stockholders. The rights of the holders of our common stock will be subject to the rights of the holders of any preferred stock that may be issued in the future. The issuance of preferred stock could delay, deter or prevent a change in control and could adversely affect the voting power or economic value of your shares.

In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified Board of Directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors;
- limitations on the ability of our stockholders to call special meetings;
- limitations on the ability of our stockholders to act by written consent in certain circumstances;
- a separate vote of 75% of the voting power of the outstanding shares of capital stock in order for stockholders to amend the bylaws in certain circumstances; and
- advance notice provisions for stockholder proposals and nominations for elections to our Board of Directors to be acted upon at meetings of stockholders.

In addition, the rights agreement will impose a significant penalty on any person or group that acquires, or begins a tender or exchange offer that would result in such person acquiring, 20% or more of our outstanding common stock without approval from our Board of Directors.

Although we believe these provisions protect our stockholders from coercive or otherwise unfair takeover tactics and thereby provide an opportunity to receive a higher bid by requiring potential acquirers to negotiate with our Board of Directors, these provisions apply even if the offer may be considered beneficial by some stockholders. Further, these provisions may discourage potential acquisition proposals and may delay, deter or prevent a change of control of our company, including through unsolicited transactions that some or all of our stockholders might consider to be desirable. As a result, efforts by our stockholders to change our direction or our management may be unsuccessful.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

Information regarding our properties is contained in Part I, “Item 1. Business” and Part II, “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Item 3. Legal Proceedings.

In March 2001, a predecessor of LPR Canada acquired interests in certain heavy oil assets in the Eyehill Creek area of Alberta from certain predecessors of Encana Corporation (“Encana”). In 2003, IFP Technologies (Canada) Inc. (“IFP”) filed a statement of claim with the Court of Queen’s Bench of Alberta (the “Court”) against Encana and certain of its predecessors and affiliates and against certain predecessors of LPR Canada, claiming, among other things, damages in the amount of \$45.6 million or, in the alternative, for an accounting of 20% of the revenues that the predecessors of LPR Canada have received from the acquired properties. At the outset of the trial, IFP amended its claim to increase the damages being sought to \$56.7 million, plus interests and costs. The trial of this action occurred in the first quarter of 2011, and we are awaiting the judgment of the Court. Although we are unable to predict the final outcome of this case, we believe that the allegations of this lawsuit are without merit, and in any event are largely covered by the terms of an indemnity between the predecessors of Encana and the predecessors of LPR Canada. We have and intend to continue to vigorously defend the action.

We are a party to various other lawsuits, claims and proceedings in the ordinary course of business. These proceedings are subject to uncertainties inherent in any litigation, and the outcome of these matters is inherently difficult to predict with any certainty. We believe that the amount of any potential loss associated with these proceedings would not be material to our consolidated financial position; however, in the event of an unfavorable outcome, the potential loss could have an adverse effect on our results of operations and cash flow.

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 Information

Our common stock is listed on the NYSE, our principal United States market, and on the Toronto Stock Exchange ("TSX"), our principal Canadian market, in each case under the symbol "LPR."

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

	<u>High</u>	<u>Low</u>
2011		
Second Quarter(1)	US\$13.09	US\$10.15
Third Quarter	US\$12.30	US\$ 6.58
Fourth Quarter	US\$ 8.21	US\$ 5.38
2012		
First Quarter (through and including March 20, 2012)	US\$ 7.80	US\$ 6.51

(1) Represents the period from May 26, 2011, the date on which our common stock began trading on the NYSE, through June 30, 2011.

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

	<u>High</u>	<u>Low</u>
2011		
Second Quarter(1)	\$12.68	\$10.25
Third Quarter	\$11.58	\$ 6.95
Fourth Quarter	\$ 8.23	\$ 5.74
2012		
First Quarter (through and including March 20, 2012)	\$ 7.73	\$ 6.54

(1) Represents the period from May 26, 2011, the date on which our common stock began trading on the TSX, through June 30, 2011.

On March 20, 2012, the last sale price of our common stock, as reported on the NYSE and the TSX, was US\$6.96 per share and \$6.91 per share, respectively.

Holder

The number of stockholders of record of our common stock was approximately 518 on March 20, 2012.

Dividends

We have not paid any cash dividends on our common stock since our IPO. The future payment of cash dividends, if any, on our common stock is within the discretion of our Board of Directors and will depend on our earnings, capital requirements, financial condition and other relevant factors. We do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain our future earnings for use in the operation and expansion of our business. Additionally, our bank credit facility and the indenture governing the Senior Notes restrict our ability to pay dividends. For information regarding restrictions on our payment of dividends, see note 9 to our consolidated financial statements.

Equity Compensation Plans

See Part III, “Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters,” for information regarding our equity compensation plans as of December 31, 2011.

Repurchase of Equity Securities

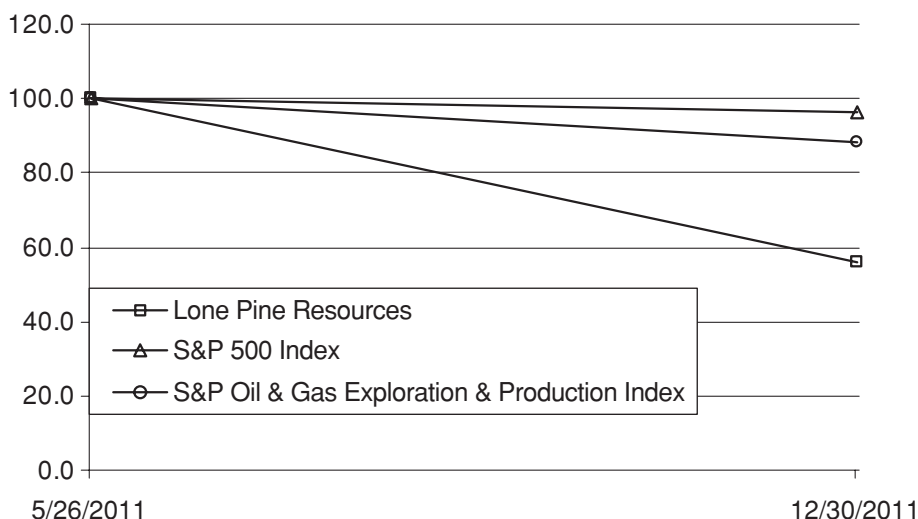
Neither we nor any “affiliated purchaser” repurchased any of our equity securities in the quarter ended December 31, 2011.

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 of 1933, as amended, or the Securities Exchange Act of 1934, as amended (“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 shown below compares the cumulative total return to Lone Pine Resources Inc.’s common stockholders as compared to the cumulative 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 500 O&G E&P”) since the time of our IPO. The comparison was prepared based upon the following assumptions:

- \$100 was invested in our common stock and invested in the S&P 500 and the S&P 500 O&G E&P on May 26, 2011 at the closing prices on such date; and
- Dividends are reinvested.



Item 6. Selected Financial Data.

The following table sets forth selected financial data of Lone Pine as of and for each of the years in the five-year period ended December 31, 2011.

Our consolidated financial statements relating to the periods prior to our inception (September 30, 2010) reflect the financial position, results of operations, cash flows or other information, as the case may be, of our predecessor, LPR Canada. Our consolidated financial statements relating to the period from our inception through the completion of our IPO (June 1, 2011) reflect the financial position, results of operations, cash flows or other information, as the case may be, of Lone Pine and its predecessor, LPR Canada, on a combined basis. Our consolidated financial statements relating to the period subsequent to and including June 1, 2011 reflects the financial position, results of operations, cash flows or other information, as the case may be, of Lone Pine and its consolidated subsidiaries.

Our consolidated financial statements as of and for each of the years in the four-year period ended December 31, 2010 were reported using the U.S. dollar. Effective October 1, 2011, Lone Pine changed its reporting currency to the Canadian dollar. With the change in reporting currency, all comparative financial information has been recast from U.S. dollars to Canadian dollars to reflect our consolidated financial statements as if they had been historically reported in Canadian dollars, consistent with ASC 830, *Foreign Currency Matters*. The consolidated U.S. dollar balance sheet information was translated into the Canadian dollar reporting currency by translating assets and liabilities at the end-of-period exchange rate and translating equity balances at historical exchange rates. The consolidated statement of operations information was translated into Canadian dollars using the weighted average exchange rate for the period. The resulting foreign currency translation adjustment is reported as a component of other comprehensive income and accumulated other comprehensive income.

The Company changed the functional currency of Lone Pine Resources Inc. prospectively from October 1, 2011 from the U.S. dollar to the Canadian dollar. The change in functional currency did not have a significant impact on our consolidated financial statements for the year ended December 31, 2011 as Lone Pine's operations are primarily carried out by its operating subsidiary, LPR Canada. The functional currency of LPR Canada has not changed and continues to be the Canadian dollar. As a result of this change in functional currency, there is no difference between the reporting currency and the functional currency of Lone Pine and any of its subsidiaries.

For a detailed discussion of the selected financial data contained in the following table, refer to Part II, "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8—Financial Statements and Supplementary Data."

	Year ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands of Canadian dollars)				
Statement of operations data:					
Revenues	191,200	151,208	127,209	263,484	203,760
Net earnings (loss)	34,803	32,825	(177,746)	48,877	60,183
Balance sheet data (at period end):					
Total assets	992,301	711,351	541,919	885,378	784,808
Long-term debt(1)	331,000	—	—	115,000	128,000
Capital lease obligations	6,894	—	—	—	—
Amounts due to Forest(2)	252	287,669	164,714	129,187	83,717

(1) Represents amounts due under long-term financing arrangements.

(2) Includes our note payable to Forest, intercompany advances due to Forest and accrued interest payable to Forest.

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

You should read the following discussion and analysis of our financial condition and results of operations in conjunction with the consolidated financial statements and the related notes contained elsewhere in this Form 10-K. All expectations, forecasts, assumptions and beliefs about our future financial results, condition, operations, strategic plans and performance are forward-looking statements, as described in more detail under "Cautionary Note Regarding Forward-Looking Statements." Our actual results may differ materially because of a number of risks and uncertainties. See Part I, "Item 1A. Risk Factors" for additional information regarding known material risks.

Unless the context otherwise requires, all operating data presented in this Form 10-K on a per unit basis is calculated based on net sales volumes, all references to "dollars," "\$" or "Cdn\$" in this Form 10-K are to Canadian dollars, and all references to "U.S. dollars" or "US\$" are to United States dollars.

Overview

We are an independent oil and gas exploration, development and production company with operations in Canada. Our reserves, producing properties and exploration prospects are located in the provinces of Alberta, British Columbia and Quebec and the Northwest Territories. We were incorporated under the laws of the State of Delaware on September 30, 2010, and prior to our IPO on June 1, 2011, we were a wholly-owned subsidiary of Forest. Our predecessor, LPR Canada, was acquired by Forest in 1996 and transferred to us prior to completion of our IPO. Upon completion of our IPO, Forest retained the controlling interest in us, owning 82% of the outstanding shares of our common stock. On September 30, 2011, Forest distributed all of the outstanding shares of our common stock that it owned to its shareholders. As a result of the Distribution, Forest has no remaining ownership interest in us.

DeGolyer and MacNaughton, our independent reserves engineers, estimated our proved reserves to be approximately 401 Bcfe as of December 31, 2011, of which approximately 26% was oil and natural gas liquids, approximately 74% was natural gas and approximately 53% was classified as proved developed reserves. As of December 31, 2011, we had approximately 151 gross (125 net) proved undeveloped drilling locations and approximately 1.1 million gross (0.8 million net) acres of land (approximately 79% of which was undeveloped).

Financial and other information disclosed herein relating to the time prior to our inception (September 30, 2010) reflects the financial position, results of operations, cash flows or other information, as the case may be, of our predecessor, LPR Canada. Financial and other information disclosed relating to the period from our inception through the completion of our IPO (June 1, 2011) reflects the financial position, results of operations, cash flows or other information, as the case may be, of Lone Pine and its predecessor, LPR Canada, on a combined basis. Financial and other information disclosed relating to the period subsequent to and including June 1, 2011 reflects the financial position, results of operations, cash flows or other information, as the case may be, of Lone Pine and its consolidated subsidiaries.

Change in Functional Currency and Reporting Currency

Effective October 1, 2011, Lone Pine changed its functional currency and reporting currency from the U.S. dollar to the Canadian dollar. The change in functional currency did not have a significant impact on our consolidated financial statements for either the fourth quarter of 2011 or the year ended December 31, 2011 as Lone Pine's operations are primarily carried out by its operating subsidiary, LPR Canada. The functional currency of LPR Canada has not changed and continues to be the Canadian dollar.

Prior to the Distribution, Lone Pine used the same reporting currency as Forest, which was the U.S. dollar, in its consolidated financial statements. However, after the Distribution, our management determined that our financial statements should be presented using the Canadian dollar, in order to

present Lone Pine's financial statements in the same currency as its functional currency, and to minimize the impact of changes in foreign currency exchange rates on our financial statements. The determination to change Lone Pine's reporting currency was based on a number of factors, which included the following: (1) Lone Pine has no assets or operations in the United States, (2) substantially all of Lone Pine's operations are conducted in a single functional currency, the Canadian dollar, and (3) the reporting currency selected, the Canadian dollar, is the same as the functional currency.

Prior to the change in reporting currency, our consolidated statements of operations were translated from Canadian dollars using the weighted average exchange rate for the period. The resulting foreign currency translation adjustment was reported as a component of other comprehensive income and accumulated other comprehensive income. As a result of our change in reporting currency, all comparative financial information has been recast from U.S. dollars to Canadian dollars to reflect our consolidated financial statements as if they had been historically reported in Canadian dollars, consistent with ASC 830, *Foreign Currency Matters*. The consolidated U.S. dollar balance sheet at December 31, 2010 was translated into Canadian dollars by translating assets and liabilities at the end-of-period exchange rate and translating equity balances at historical exchange rates.

As a result of our change in functional currency and reporting currency, there is no difference between the reporting currency and the functional currency of Lone Pine Resources Inc. and any of its operating subsidiaries. Following the changes in functional currency and reporting currency, we will be subject to foreign currency exchange rate risk relating to the Senior Notes, certain of our derivative instruments and our delivery commitment of approximately 21,000 MMBtu/d of natural gas under a long-term sales contract expiring in 2014.

See “—Critical Accounting Policies, Estimates, Judgments and Assumptions—*Change in Reporting and Functional Currency*” for more information about our change in reporting currency, including the reasons for the change, the manner in which the change has been applied to recast prior period financial statements and the major financial statement categories that are denominated in U.S. dollars, and for certain U.S. dollar financial information as of and for the year ended December 31, 2011. See also note 2 to our consolidated financial statements.

Financial and Operating Performance

Our financial and operating performance for 2011 included the following highlights:

- On June 1, 2011, we completed our IPO of 15 million shares of our common stock. In connection with our IPO and pursuant to our separation and distribution agreement with Forest, Forest contributed to us its ownership interest in LPR Canada in exchange for 69,999,999 shares of our common stock and a cash distribution of \$28.7 million. We received net proceeds from our IPO of approximately \$173.1 million and used these net proceeds to pay \$28.7 million to Forest as partial consideration for Forest's contribution to us of Forest's direct and indirect interests in its Canadian operations. We used the remaining net proceeds and borrowings under our bank credit facility to repay outstanding indebtedness owed to Forest, including intercompany advances and accrued interest.
- Our average daily net sales volumes for the fourth quarter of 2011 and for the year ended December 31, 2011 were 99 MMcf/d and 94 MMcf/d respectively, and our average daily oil and NGLs net sales volumes for the fourth quarter of 2011 increased 27% to 4,499 bbls/d, compared to 3,544 bbls/d in the third quarter of 2011 as our average net liquids percentage increased from 22% to 27%.
- We drilled a total of 47 gross (47 net) horizontal light oil wells at Evi and 6 gross (5.5 net) natural gas wells in the Deep Basin with a 100% success rate.
- We generated Adjusted EBITDA of \$128.2 million, a 27% increase over 2010 and Adjusted Discretionary Cash Flow of \$118.4 million, a 26% increase over 2010.

During February 2012, LPR Canada completed the Senior Notes offering. The net proceeds of approximately \$192 million were used to partially repay borrowings outstanding under our bank credit facility. The Senior Notes are guaranteed by Lone Pine and all of Lone Pine's wholly-owned subsidiaries (other than LPR Canada).

Recent Trends and Outlook for 2012

Beginning in the second half of 2008 and continuing throughout 2011, Canada, the United States and other industrialized countries experienced a significant economic slowdown. During the same time period, North American natural gas supply increased as a result of increased domestic unconventional natural gas development and associated natural gas from oil development. In the second half of 2008, oil and natural gas prices declined dramatically. While oil and NGL prices have steadily improved since the first quarter of 2009, North American natural gas prices have remained at low levels and declined further in late 2011 as a result of increased supply and weak domestic demand in the United States. We do not expect natural gas prices to improve significantly in 2012. As a result, we plan to focus our capital expenditures in 2012 primarily on light oil opportunities.

Capital Budget for 2012

We have established a capital budget of approximately \$200 million to \$220 million for 2012 and plan to focus our drilling program almost entirely on our light oil opportunities in the Evi area. We have elected to pursue a 2012 capital program designed to maintain financial flexibility, while focusing on high margin light oil projects. We plan to fund our 2012 capital budget primarily through cash flow from operating activities, as well as borrowings under our bank credit facility.

We plan to allocate approximately \$165 million, or approximately 80%, of our total capital budget to light oil development in the Evi area. We plan to drill and complete up to 48 gross (48 net) horizontal wells in the Evi area in 2012 and to continue to advance development through further downspacing and additional infill drilling. We expect to complete the planned drilling program in the Evi area with the two-rig program that we currently have in place. We also intend to continue to expand our facilities in the Evi area to accommodate the growing crude oil volumes in the area and continue investment in our operated waterflood pilot project that we initiated in 2011.

Given the current disparity between oil and natural gas prices, we intend to allocate minimal capital towards our natural gas properties at this time. Since we have no significant near term lease expiries or drilling obligations on our natural gas assets, we plan to focus almost exclusively on light oil projects while North American natural gas prices continue to trade at multi-year lows. Should natural gas prices recover through 2012, we expect to be able to alter our spending plans and allocate capital to our drill-ready natural gas projects.

Our 2012 capital budget is detailed below.

	(In millions)
Drilling and completion	
Light oil	\$150.0 - \$160.0
Natural gas	10.0 - 10.0
Total	\$160.0 - \$170.0
Equipment and facilities	20.0 - 25.0
Land maintenance and general and administrative expenses	20.0 - 25.0
Total capital	<u>\$200.0 - \$220.0</u>

Acquisitions and Divestitures

In 2011, we increased our Evi land position to 64,320 gross (57,382 net) acres through purchases at Crown land sales. The acquired acreage represents a significant addition to our existing contiguous land holdings in the Evi field and our future light oil drilling inventory.

In April 2011, we acquired certain natural gas properties located in the Narraway/Ojay fields for \$74.4 million. This acquisition increased our working interests in certain properties already owned and operated by LPR Canada in the Narraway field from approximately 50% to 100% and provided us with additional capacity in gathering systems and a gas plant in the Narraway field. In addition, this acquisition increased our acreage position by approximately 85,100 gross (35,700 net) acres.

As we have expanded into new plays, we also have divested assets that did not meet our development growth strategy. Starting in the fourth quarter of 2009 and through December 31, 2011, we divested approximately \$159 million of certain non-core or non-operated oil and gas properties, primarily in December 2009 and April 2010, which, at the time the divestitures occurred, had a combined net production rate of 16 MMcfe/d.

How We Evaluate Our Operations

We use a variety of financial and operational measures to assess our performance, including:

- volumes of oil, natural gas and NGLs produced and sold;
- realized commodity prices;
- production costs; and
- earnings before interest, taxes, depreciation, depletion and amortization (“DD&A”) and other non-cash items (“Adjusted EBITDA”) and cash provided by operating activities before changes in working capital items (“Adjusted Discretionary Cash Flow”).

Volumes of Oil, Natural Gas and NGLs Produced and Sold

The volumes of oil, natural gas and NGLs that we produce and sell are driven by several factors, including:

- the amount of capital we invest in the exploration, development and acquisition of oil and natural gas properties, including the drilling of new wells and the recompletion of existing wells;
- the rate at which production volumes on our wells naturally decline;
- the royalty percentage that is levied on our sales volumes by Canadian provinces; and
- the amount of production volumes associated with oil and natural gas properties we may divest from time to time.

Average daily net sales volumes for the years ended December 31, 2011, 2010 and 2009 are set forth in the table below. See “Results of Operations—Years Ended December 31, 2011, 2010 and 2009—Oil and Natural Gas Volumes and Revenues” for an evaluation of the information presented.

	Year Ended December 31,		
	2011	2010	2009
Net sales volumes (MMcfe/d)	94	77	78
Royalties (percentage of working interest sales volumes)	7%	8%	11%
Pro forma net daily sales volumes giving effect to oil and natural gas property divestitures (MMcfe/d)(1)	<u>94</u>	<u>76</u>	<u>62</u>

- (1) We divested of certain non-core oil and natural gas properties, primarily in December 2009 and April 2010 that, at the time the divestitures occurred, had a combined net production rate of 16 MMcfe/d. The pro forma net daily sales volumes for oil and natural gas property divestitures represent the net daily sales attributable to the oil and natural gas properties in which we had an ownership interest as of December 31, 2011.

Realized Commodity Prices

We market our production to a variety of purchasers based on regional pricing, and the prices that we receive are determined by various factors but are primarily driven by global and regional supply and demand fundamentals. NYMEX WTI futures prices are widely-used benchmarks in the pricing of oil and NGLs, and NYMEX Henry Hub and AECO futures prices are used as benchmarks in the pricing of natural gas. The prices realized for each of our products compared to the NYMEX and AECO benchmark prices, or differential, will depend on various factors, which are discussed by product below.

The table below sets forth the various benchmark prices in U.S. dollars, as well as the prices that we received per unit of volume for each of our products compared to the benchmark prices for the periods indicated. Given our change in reporting currency, we have also presented our realized prices in Canadian dollars.

	Year Ended December 31,					
	2011		2010		2009	
	US	Cdn	US	Cdn	US	Cdn
Oil:						
Average NYMEX WTI price (per bbl)	\$95.12		\$79.53		\$61.80	
Average oil sales price (per bbl)	84.64	83.89	67.51	69.88	51.14	57.46
Differential to NYMEX WTI	\$10.48		\$12.02		\$10.66	
Natural gas:						
Average NYMEX Henry Hub price (per MMBtu)	\$ 4.04		\$ 4.39		\$ 3.98	
Average natural gas sales price (per Mcf)	3.48	3.42	3.71	3.84	3.15	3.59
Differential to NYMEX Henry Hub	\$ 0.56		\$ 0.68		\$ 0.83	
Average AECO price (per MMBtu)	\$ 3.73		\$ 3.95		\$ 3.50	
Average natural gas sales price (per Mcf)	3.48	3.42	3.71	3.84	3.15	3.59
Differential to AECO	\$ 0.25		\$ 0.24		\$ 0.35	
NGLs:						
Average NYMEX WTI price (per bbl)	\$95.12		\$79.53		\$61.80	
Average NGL sales price (per bbl)	62.17	61.43	51.68	53.65	30.82	34.93
Percentage of NYMEX WTI	<u>65%</u>		<u>65%</u>		<u>50%</u>	

Oil Differentials

The primary factors influencing our oil differential to the NYMEX WTI price are (1) the quality of our oil and (2) the proximity of our oil production to major consuming and refining markets.

Among other things, there are two characteristics that determine the quality of our oil: (1) the oil's American Petroleum Institute ("API") gravity and (2) the oil's sulfur content by weight. In general, lighter oil (with higher API gravity) sells at a higher price than heavier oil, because lighter oil produces a larger number of lighter liquid products, such as gasoline, that have a higher resale value. On average, the oil that we produce is approximately 35 degrees API. Oil with low sulfur content, or "sweet" crude oil, such as the oil we produce at Evi, is less expensive to refine and, as a result, normally sells at a higher price than high sulfur-content oil, or "sour" crude oil.

The proximity of our oil production to major consuming and refining markets also impacts our oil differentials. Oil that is produced close to major consuming and/or refining markets, such as Edmonton or Hardisty in Alberta, is in higher demand than oil that is produced farther from these markets and, consequently, realizes a higher price due to the implied costs that must be incurred by the buyer of the oil at or near the wellhead to transport the oil to the consuming and refining markets.

Natural Gas Differentials

The primary factors influencing natural gas differentials include the proximity of natural gas production to consuming markets or, in instances when natural gas is produced in remote areas away from consuming markets, the amount of natural gas pipeline "takeaway capacity" available to transport natural gas produced to areas with higher demand. Generally, natural gas produced in close proximity to areas that consume large quantities of natural gas will command higher prices, as will natural gas produced in areas with adequate takeaway capacity to those consuming markets. The majority of the natural gas that we produce can access adequate takeaway capacity to major consuming markets and is transported to those markets under firm transportation contracts.

As of March 20, 2012, we had a delivery commitment of approximately 21,000 MMBtu/d of natural gas, which provides for a price equal to the greater of (1) the NYMEX Henry Hub price less US\$1.49 and (2) US\$1.00 per MMBtu to a buyer through October 31, 2014, unless the NYMEX Henry Hub price exceeds US\$6.50 per MMBtu, at which point we share the amount of the excess equally with the buyer. Accordingly, when the NYMEX Henry Hub price trades above US\$6.50 per MMBtu, our reported differentials will widen, as was the case in 2008. Conversely, the contract guarantees a floor price of US\$1.00 per MMBtu after deducting US\$1.49 from the NYMEX Henry Hub price and our reported differential would narrow in this case.

NGL Realizations

NGL realizations, which are generally evaluated as a percentage of the NYMEX WTI price, are primarily driven by the relative composition of liquids. NGLs are primarily composed of five marketable components, which, ordered from lightest to heaviest, are: (1) methane, (2) ethane, (3) propane, (4) butanes and (5) pentanes. The heavier liquid components normally realize higher prices than the lighter components. Our NGL realizations were higher in 2011 and 2010 compared to 2009 because of the divestiture of oil and natural gas assets in April 2010, which resulted in a shift in our portfolio toward heavier, more valuable gas liquids components.

Production Costs

In evaluating our operations, we frequently monitor and assess our production expenses on a per unit of production basis, or "per Mcfe." This measure allows us to better evaluate our operating efficiency as production levels change.

Production costs are the costs incurred in the operation of producing our oil, natural gas and NGLs and are primarily comprised of lease operating expense (including workover costs), production and property taxes and transportation and processing costs. In general, lease operating expense and workover costs represent the components of production costs over which we have management control, while production and property taxes are primarily driven by the assessed valuation of our property and equipment by the taxing authorities. Transportation and processing costs are comprised of pipeline transportation costs (primarily incurred to deliver natural gas to consuming regions in order to achieve a higher sales price) and processing costs, which include the cost of separating NGLs from the natural gas stream and compressing the residual natural gas to a pressure adequate to meet pipeline requirements.

Certain components of lease operating expense are also impacted by energy and field services costs. For example, we incur power costs in connection with various production-related activities, such as pumping to recover oil and natural gas, and we purchase products, such as methanol, to prevent the freezing of gas lines. Although these costs are highly correlated with production volumes, they are also influenced by commodity prices. Certain items, however, such as direct labor and materials and supplies, generally remain fixed across broad sales volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased expenses in periods during which they are performed.

Adjusted EBITDA and Adjusted Discretionary Cash Flow

We also evaluate our performance using a non-GAAP financial measure, Adjusted EBITDA, which is calculated as net earnings (loss) plus interest expense, income tax expense (benefit), DD&A, ceiling test write-downs of oil and natural gas properties, accretion of asset retirement obligations (“ARO”), unrealized losses (gains) on derivative instruments and foreign currency exchange (gains) losses. Adjusted EBITDA also excludes the equity-accounted for portion of stock-based compensation expense, as these amounts will be settled in shares of our common stock rather than cash payments. By eliminating these items, we believe the result is a useful measure across time in evaluating our fundamental core operating performance. Our management also uses Adjusted EBITDA to manage our business, including in preparing our annual operating budget and financial projections. We believe that Adjusted EBITDA is also useful to investors because similar measures are frequently used by securities analysts, investors and other interested parties in their evaluation of companies in similar industries. As indicated, Adjusted EBITDA does not include interest expense on borrowed money, DD&A expense on capital assets or the payment of income taxes, which are all necessary elements of our operations. Because Adjusted EBITDA does not account for these and other expenses, its utility as a measure of our operating performance has material limitations. Because of these limitations, our management does not view Adjusted EBITDA in isolation and also uses other measurements, such as net earnings (loss) and revenues, to measure operating performance.

In addition to reporting cash provided by operating activities as defined under GAAP, we also present Adjusted Discretionary Cash Flow, which is a non-GAAP liquidity measure. Adjusted Discretionary Cash Flow consists of cash provided by operating activities before changes in working capital items. Management uses Adjusted Discretionary Cash Flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operating activities for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. This measure does not represent the residual cash flow available for discretionary expenditures, since we have mandatory debt service requirements and other non-discretionary expenditures that are not deducted from the measure. Because of this, its utility as a measure of our operating performance has material limitations.

For the reconciliations of Adjusted EBITDA to net earnings (loss) and Adjusted Discretionary Cash Flow to cash provided by operating activities, which are their most directly comparable GAAP measures, see “—Reconciliation of Non-GAAP Measures.”

Results of Operations—Years Ended December 31, 2011, 2010 and 2009

The following table sets forth selected financial results for the years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except volumes and per unit data)		
Oil and natural gas sales	\$191,170	\$151,184	\$ 127,396
Total natural gas equivalent—net sales volumes (MMcfe)(1)	34,319	28,208	28,384
Realized equivalent sales per net Mcfe	\$ 5.57	\$ 5.36	\$ 4.49
Net earnings (loss)	\$ 34,803	\$ 32,825	(177,746)
Adjusted EBITDA(2)	\$128,247	\$101,297	\$ 75,743
Adjusted discretionary cash flow(2)	\$118,410	\$ 94,248	\$ 57,394

- (1) “Net sales volumes” represents our working interest sales volumes less the amount of volumes attributable to royalties.
- (2) Adjusted EBITDA and Adjusted Discretionary Cash Flow are non-GAAP performance measures. See “—Reconciliation of Non-GAAP Measures” for a reconciliation of Adjusted EBITDA to net earnings (loss) and Adjusted Discretionary Cash Flow to cash provided by operating activities, which are the most directly comparable financial measures calculated and presented in accordance with GAAP.

Net earnings were \$34.8 million for the year ended December 31, 2011 compared to net earnings of \$32.8 million for the year ended December 31, 2010. The increase was primarily due to increases in oil and gas revenue (driven primarily by higher production volumes as well as higher oil prices) and an increase in gains on derivative instruments. These increases in net earnings were partially offset by higher operating expense, higher DD&A and an increase in income tax expense. Adjusted EBITDA increased \$27.0 million for the year ended December 31, 2011 compared to the year ended December 31, 2010, due to an increase in oil and gas revenues that was partially offset by higher operating costs incurred during 2011 because of an increase in production volumes, workovers, maintenance costs, water hauling, higher utility and chemical costs and higher general and administrative costs related to our IPO and the Distribution.

Net earnings (loss) for the years ended December 31, 2010 and 2009 were primarily impacted by changes in oil and gas sales driven by oil, natural gas and NGL price fluctuations; however, net earnings (loss) did not change proportionately to the changes in oil and gas sales due to (1) non-cash foreign currency gains and losses in each period presented and (2) a \$251.0 million non-cash ceiling test write-down recorded in the first quarter of 2009 caused by a significant decline in natural gas prices as of March 31, 2009 (see “—Critical Accounting Policies, Estimates, Judgments and Assumptions—*Full Cost Method of Accounting*” for information on ceiling test write-downs). Adjusted EBITDA, which excludes the impact of these two non-cash items, was highly correlated with the changes in oil and gas sales for the year ended December 31, 2010 and 2009.

A discussion of the components of the changes in our results of operations follows.

Oil and Natural Gas Volumes and Revenues

Oil, natural gas and NGL sales volumes and revenues (which are reported net of royalties) and average sales prices by product for the years ended December 31, 2011, 2010 and 2009 are set forth in the table below.

	Year Ended December 31,		
	2011	2010	2009
Net sales volumes(1):			
Oil (Mbbls)	1,110	828	626
NGLs (Mbbls)	82	134	230
Natural gas (MMcf)	27,167	22,436	23,248
Total equivalent daily net sales volumes (MMcfe/d)	94	77	78
Total equivalent daily net sales volumes (boe/d) . . .	15,667	12,883	12,967
Revenues (in thousands):			
Oil	\$ 93,114	\$ 57,863	\$ 35,973
NGLs	5,037	7,189	8,035
Natural gas	93,019	86,132	83,388
Total oil and natural gas revenues	\$191,170	\$151,184	\$127,396
Average sales price per unit:			
Oil (per bbl)	\$ 83.89	\$ 69.88	\$ 57.46
NGLs (per bbl)	61.43	53.65	34.93
Natural gas (per Mcf)	3.42	3.84	3.59
Total equivalent (Mcfe)	\$ 5.57	\$ 5.36	\$ 4.49
Total equivalent (boe)	\$ 33.42	\$ 32.16	\$ 26.94

- (1) “Net sales volumes” represents our working interest sales volumes less the amount of volumes attributable to royalties.

Net sales volumes for the year ended December 31, 2011 increased 22% to 94 MMcfe/d from 77 MMcfe/d for the year ended December 31, 2010. Excluding the volumes relating to properties sold in 2009 and 2010, the increase would be 24% for the year ended December 31, 2011. The increases were primarily due to new drilling activity in our Evi and Narraway/Ojay fields, as well as the acquisition of additional Narraway/Ojay producing properties in April 2011, partially offset by natural declines in other areas.

Net sales volumes for the year ended December 31, 2010 were 77 MMcfe/d compared to 78 MMcfe/d in 2009. The 1 MMcfe/d decrease was due to the divestiture of non-core oil and gas properties primarily in December 2009 and April 2010 that, at the time the divestitures occurred, had a combined net production rate of 16 MMcfe/d. The impact from the oil and gas property divestitures on our 2010 net sales volumes was nearly offset by production increases attributable to new wells drilled in 2010.

Oil and natural gas revenues were \$191 million for the year ended December 31, 2011, a 26% increase as compared to \$151 million for the year ended December 31, 2010. The increase in revenues was due to an increase in sales volumes of 22%, as well as higher realized oil prices in each period. In addition, oil differentials widened in the second and third quarters of 2011 as a result of the shutdown of the pipeline used to transport oil from Evi to market. This necessitated trucking the oil to market. The pipeline was back in operation in the fourth quarter of 2011.

Oil and natural gas revenues were \$151 million and \$127 million for the years ended December 31, 2010 and 2009, respectively. The 19% increase in revenues was primarily due to a 19% increase in the average sales price per unit. See “—How We Evaluate Our Operations—Realized Commodity Prices”

above for a comparison of our realized commodity prices compared to commonly used benchmark prices.

Oil and Gas Production Expense

The table below sets forth the detail of production expense for the periods indicated.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except per Mcfe data)		
Production expense:			
Lease operating expenses	\$38,789	\$26,547	\$31,255
Production and property taxes	2,337	2,513	3,165
Transportation and processing costs	17,252	11,104	9,197
Total	<u>\$58,378</u>	<u>\$40,164</u>	<u>\$43,617</u>
Production expense per Mcfe:			
Lease operating expenses	\$ 1.13	\$ 0.94	\$ 1.10
Production and property taxes	0.07	0.09	0.11
Transportation and processing costs	0.50	0.39	0.33
Total	<u>\$ 1.70</u>	<u>\$ 1.42</u>	<u>\$ 1.54</u>

Lease Operating Expenses

Lease operating expenses in the year ended December 31, 2011 were \$38.8 million, or \$1.13 per Mcfe, compared to \$26.5 million, or \$0.94 per Mcfe, in the year ended December 31, 2010. The \$12.2 million increase in lease operating expenses was primarily due to an increase in production volumes, workovers, maintenance costs, water hauling and utility and chemical costs. Additional workover activity as noted above accounted for \$3.2 million of the increase. Maintenance costs increased \$3.7 million due primarily to start-up costs associated with bringing a large number of wells on-line in late 2010, which were previously shut-in due to infrastructure constraints. In conjunction with these wells coming on-line, a new remotely-located compressor facility was also placed in service. For several months after the initial start-up of the new wells and the new compressor facility, we incurred significant mechanical and electrical costs tied to the start-up, including troubleshooting costs related to the new facilities and the prolonged shut-in of the wells. Maintenance costs at Evi also increased due to the heightened activity in the area combined with some harsh operating conditions. Costs of trucking and disposing of water increased by \$1.3 million. Utility costs increased \$0.6 million primarily due to higher utility rates as well as an increase in usage. Chemical costs, which primarily include methanol and glycol used to prevent the freezing of gas lines, increased \$0.6 million for the year. Other increases were generally related to variable costs associated with increased production.

Lease operating expenses decreased 15% to \$26.5 million in the year ended December 31, 2010, compared to \$31.3 million for the year ended December 31, 2009. Lease operating expenses also decreased \$0.16 on a per-unit of production basis to \$0.94 per Mcfe due primarily to cost-reduction initiatives.

Production and Property Taxes

Production and property taxes, which primarily consist of production taxes levied on freehold production and property taxes (ad valorem taxes) assessed by local governments, were lower in 2011 and 2010 compared to 2009, primarily due to the divestiture of properties with freehold production as well as declining production from existing freehold properties.

Transportation and Processing Costs

Transportation and processing costs primarily consist of gas transportation costs and field-level gas gathering and processing costs. The increases to \$0.50 and \$0.39 per Mcfe for the year ended December 31, 2011 and for the year ended December 31, 2010, respectively, were primarily due to additional capacity purchased for our Narraway/Ojay production as well as higher fees for gathering and processing in the area.

General and Administrative Expense

The following table summarizes the components of general and administrative expense incurred during the years ended December 31, 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except per Mcfe data)		
Stock-based compensation costs	\$ 2,409	\$ 3,644	\$ 1,456
Management fees charged by Forest	2,479	3,121	1,972
Other general and administrative costs	12,713	8,598	10,649
General and administrative costs capitalized (including stock-based compensation)	(4,486)	(5,773)	(6,108)
General and administrative expense	\$13,115	\$ 9,590	\$ 7,969
General and administrative expense per Mcfe	\$ 0.38	\$ 0.34	\$ 0.28

Stock-Based Compensation Costs

Until the date of the Distribution, stock-based compensation costs primarily represented the amortization of the value of stock options and performance and phantom stock units awarded by Forest, our former parent company, as part of its equity incentive plans. We established our own stock-based compensation plan in 2011, and we account for most of the units that had been issued under this plan as of December 31, 2011 as liability-settled units.

The estimated fair value of the phantom stock awards awarded by Forest, which were accounted for as a liability since the units were able to be settled in cash or shares at Forest's discretion, were adjusted quarterly based on changes in Forest's common stock price. As such, the expense recognized from period to period was subject to fluctuations. The decrease in stock-based compensation costs for the year ended December 31, 2011 was primarily due to a decrease in Forest's stock price partially offset by the additional costs associated with accelerated vesting resulting from completion of the Distribution.

Management Fees Charged by Forest

Management fees charged by Forest were intended to cover various costs incurred by Forest on our behalf, including, among other items, legal, accounting and treasury services and insurance costs. The increase in the year ended December 31, 2011 compared to the corresponding period in 2010 is primarily due to the costs Forest incurred in preparation for our IPO and the Distribution, which we were obligated to reimburse Forest under the separation and distribution agreement. This includes charges from Forest under the transition services agreement of \$0.3 million.

Other General and Administrative Costs

Other general and administrative costs are primarily made up of the salaries and related benefit costs for our employees and office lease costs. Other general and administrative costs increased in the

year ended December 31, 2011 compared to the corresponding periods in 2010 primarily as a result of direct costs we incurred in preparation for our IPO as well as increases in staffing to absorb the additional corporate functions that were historically provided to us by Forest. Other general and administrative costs were consistent between the years ended December 31, 2010 and 2009, but have trended lower in the last several years as a result of ongoing cost-control initiatives. As a public company, we have incurred and expect to continue to incur incremental general and administrative costs.

General and Administrative Costs Capitalized

Under the full cost method of accounting, general and administrative costs directly related to exploration and development activities are capitalized. The percentage of general and administrative costs capitalized ranged from 25% to 43% during the periods presented.

Depreciation, Depletion and Amortization

The following table summarizes DD&A expense incurred during the periods indicated.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except per Mcfe data)		
Depreciation, depletion and amortization	\$85,751	\$65,811	\$64,358
Depreciation, depletion and amortization per Mcfe . . .	\$ 2.50	\$ 2.33	\$ 2.27

For the year ended December 31, 2011, DD&A was \$85.8 million, or \$2.50 per Mcfe, compared to \$65.8 million, or \$2.33 per Mcfe, for the year ended December 31, 2010. The increase in DD&A is primarily due to a ceiling test write-down recorded as of March 31, 2009, which reduced our DD&A rate to \$2.05 per Mcfe in the quarter immediately following the ceiling test. Our depletion rate has steadily increased since the ceiling test write-down occurred, as we have added proved oil and gas reserves to our depletable base at per-unit rates that have exceeded \$2.05 per Mcfe, primarily due to a higher percentage of our capital expenditures directed towards oil projects.

DD&A increased \$0.06 per Mcfe to \$2.33 per Mcfe in 2010 from \$2.27 per Mcfe in 2009. The increase was primarily due to the \$251.0 million ceiling test write-down recorded as of March 31, 2009 that substantially reduced our DD&A rate in 2009. As we have added proved oil and gas reserves to our depletable base at higher average per-unit rates in excess of \$2.27 since 2009, our DD&A rate has steadily increased, including during 2011.

Ceiling Test Write-Down of Oil and Natural Gas Properties

Pursuant to the ceiling test limitation prescribed by the SEC for companies using the full cost method of accounting, the calculation uses prices that are based on the average of the first-day-of-the-month prices during the 12-month period prior to the reporting date. Although we did not recognize a ceiling test write-down at December 31, 2011, the recent decline in the price of natural gas has increased the possibility of recognizing non-cash ceiling test write-downs in future periods.

In 2009, we recorded a non-cash ceiling test write-down totaling \$251.0 million in the first quarter, which was the result of a significant decline in the natural gas price in the first quarter of 2009. See “—Critical Accounting Policies, Estimates, Judgments and Assumptions—*Full Cost Method of Accounting*” and Part I, “Item 1A. Risk Factors—Risks Related to Our Business—*Lower oil, natural gas and NGL prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values.*”

Interest Expense

The following table summarizes interest expense incurred during the years ended December 31, 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Interest costs	\$10,709	\$7,981	\$18,466
Interest costs capitalized	(675)	(791)	—
Interest expense	<u>\$10,034</u>	<u>\$7,190</u>	<u>\$18,466</u>

Interest expense presented in the table above was primarily associated with borrowings incurred under our bank credit facility and our note payable to Forest. In December 2009, outstanding balances under our previous bank credit facility were repaid using proceeds from asset divestitures and borrowings under the note payable to Forest. From December 2009 through the completion of our IPO on June 1, 2011, we primarily utilized borrowings from Forest to supplement our working capital needs. On June 1, 2011, we used the proceeds from our IPO and borrowings under our bank credit facility to repay the intercompany note and advances to Forest. The increase in the interest costs for the year ended December 31, 2011 compared to the comparable period in 2010 is primarily due to an increase in average debt balances during the periods presented, offset by lower average interest rates on the note payable to Forest.

Interest costs decreased \$10.5 million for the year ended December 31, 2010 to \$8.0 million, compared to \$18.5 million for the year ended December 31, 2009, due primarily to a decrease in the variable interest rate on the note payable to Forest in 2010 compared to 2009. Effective January 1, 2009, the amended and restated note payable to Forest provided for a variable interest rate equal to the three month LIBOR plus a multiple of Forest's credit default swap ("CDS") rate. During 2009, both LIBOR and Forest's CDS rate were higher as compared to 2010.

Interest costs capitalized in 2011 and 2010 relate to our investment in unproved acreage in the Narraway/Ojay fields as a result of our leasing activities in late 2009 and early 2010. Under the full cost method of accounting, significant investments in unproved properties on which exploration or development activities are in progress are assets qualifying for capitalization of interest costs.

Gains on Derivative Instruments

The table below sets forth unrealized and realized losses (gains) on derivatives recognized during the years ended December 31, 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Unrealized losses (gains) on derivative instruments	\$(19,786)	\$—	\$—
Realized losses (gains) on derivative instruments	(8,381)	—	—
	<u>\$(28,167)</u>	<u>\$—</u>	<u>\$—</u>

In 2011, we entered into commodity swap derivative instruments to manage our exposure to commodity price risk caused by fluctuations in commodity prices, which protects and provides certainty on a portion of our cash flows. We realized gains on these instruments in 2011, primarily because the NYMEX Henry Hub and NYMEX WTI prices were significantly lower than the prices in our contracts. The unrealized gains at December 31, 2011 were also primarily due to the forward NYMEX Henry Hub prices being significantly lower than the prices in our contracts. At December 31, 2011, our credit risk exposure related to derivative instruments was the unrealized amount of \$19.8 million.

Foreign Currency Exchange

In 2011, we realized a foreign currency exchange gain of \$32.7 million on the repayment of amounts due to Forest since the note and advances had been denominated in U.S. dollars, and the Canadian dollar had strengthened in recent years. In 2010 and 2009, our most significant foreign currency exchange amounts related to significant unrealized gains on the translation of the outstanding indebtedness and advances, which were also due to a strengthening of the Canadian dollar. See Part I, “Item 1A. Risk Factors—Risks Related to Our Business—*Our business, financial condition, cash flows and results of operations may be adversely affected by foreign currency fluctuations and economic and political developments.*”

Other, net

The table below sets forth the components of “Other, Net” in our consolidated statements of operations for the periods indicated.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Accretion of asset retirement obligations	\$1,071	\$1,073	\$1,143
Impairment of inventory	2,262	—	—
Other, net	1,205	568	365
	<u>\$4,538</u>	<u>\$1,641</u>	<u>\$1,508</u>

Accretion of ARO is the expense recognized to increase the carrying amount of the liability associated with our ARO as a result of the passage of time. See the notes to our consolidated financial statements included elsewhere in this Form 10-K for more information on our ARO.

In the fourth quarter of 2011, we recognized a \$2.3 million impairment of our inventory which primarily related to material and supplies that had been purchased for natural gas development projects. Given that our 2012 capital program will focus on crude oil development, we determined that it was appropriate to reduce the carrying value of inventory related to natural gas projects down to its current estimate of fair value, based on estimated selling prices.

Income Tax

The table below sets forth our total income tax from continuing operations and effective tax rates for the years ended December 31, 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Current income tax	\$ —	\$ —	\$ —
Deferred income tax	17,724	7,911	(63,066)
Total income tax	<u>\$17,724</u>	<u>\$7,911</u>	<u>\$(63,066)</u>
Effective tax rate	<u>34%</u>	<u>19%</u>	<u>26%</u>

Our combined federal and provincial statutory tax rate for the periods presented ranged from 26.5% to 29%; however, our effective tax rate varied from 19% to 34% primarily due to changes in valuation allowances, foreign currency exchange gains and losses taxed at 50% of the statutory rate and the impact that enacted statutory rate reductions in Canada had on our net deferred tax liabilities. See the notes to our consolidated financial statements included elsewhere in this Form 10-K for a

reconciliation of our income taxes at the statutory rate to income taxes at our effective rate for each period presented.

We have Canadian tax pools relating to the exploration, development and production of oil and natural gas that are available to reduce future Canadian income taxes. These tax pool balances are deductible on a declining balance basis ranging from 4% to 100% of the balance annually, and are composed of costs incurred for oil and natural gas properties, and developmental and exploration expenditures, as follows:

	December 31	
	2011	2010
	(In thousands)	
Canadian exploration pools (deductible at 100% annually)	\$101,470	\$ 88,699
Canadian development pools (deductible at 30% annually)	261,603	132,437
Canadian oil and natural gas property pools (deductible at 10% annually)	79,604	29,155
Canadian capital cost allowance (deductible at 4% - 25% annually)	140,133	131,166
	<u>\$582,810</u>	<u>\$381,457</u>

Other Federal Canadian tax pools and loss carryforwards available to reduce future income taxes were approximately \$6.4 million at December 31, 2011, of which \$2.3 million are deductible on a declining balance basis ranging from 20% to 100% of the balance annually, and \$4.1 million are deductible over the next five years. Other Provincial tax pools available to reduce future income taxes were approximately \$31.6 million at December 31, 2011. In addition, we had Canadian Provincial non-capital loss carryforwards of \$4.6 million, with \$2.0 million scheduled to expire in 2012 and \$2.6 million scheduled to expire in 2023. At December 31, 2011, we also had U.S. Federal operating loss carryforwards of US\$2.5 million, which are scheduled to expire in 2031.

Liquidity and Capital Resources

Our exploration, development and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operating activities, our bank credit facility and borrowings from Forest as our primary sources of liquidity. Additionally, as market conditions have permitted, we have engaged in non-core asset divestitures. Following the completion of our IPO and the Distribution, we are no longer able to borrow from Forest.

Changes in the market prices for oil, natural gas and NGLs directly impact our level of cash flow from operating activities. Natural gas has historically comprised approximately 80% of our production; as a result, our operations and cash flows have been more sensitive to fluctuations in the market price for natural gas than to fluctuations in the market price for oil. In 2011, we entered into commodity swap derivative instruments to manage our exposure to commodity price risk caused by fluctuations in commodity prices, which protect and provide certainty on a portion of our cash flows. As of March 20, 2012, we had entered into commodity swaps to hedge approximately 16 Bcfe of our projected 2012 production. This level of hedging will provide a measure of certainty of the cash flow that we will receive for a portion of our production in 2012. In the future, we may determine to increase or decrease our hedging positions. See Part II, “Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk” for more information on our derivative contracts.

As noted above, a primary source of liquidity is our bank credit facility, which has been used to fund daily operations as needed. Our bank credit facility, which matures in March 2016, is secured by a portion of our assets. Our bank credit facility had a borrowing base of \$425 million at December 31, 2011, which was subsequently reduced to \$375 million in February 2012 upon the completion of our offering of the Senior Notes. The borrowing base is subject to redetermination and to other automatic adjustments under our bank credit facility. See “—Bank Credit Facility” below for further details. As of

March 20, 2011, we had \$185 million outstanding under our bank credit facility at a weighted average interest rate of 3.2781%.

We have established a capital budget of approximately \$200 million to \$220 million for 2012 and will focus our drilling program almost entirely on our light oil opportunities. We plan to fund our 2012 capital budget primarily through cash provided by operating activities, as well as borrowings under our bank credit facility.

We believe that our cash flows provided by operating activities and the funds available under our bank credit facility will be sufficient to fund our normal recurring operating needs, anticipated capital expenditures and our contractual obligations. However, if our revenue and cash flows decrease in the future as a result of a deterioration in domestic and global economic conditions, a significant decline in commodity prices or a continuation of depressed natural gas prices, we may elect to reduce our planned capital expenditures. We believe that this flexibility to adjust our spending levels will provide us with sufficient liquidity to meet our financial obligations should economic conditions deteriorate. See Part I, “Item 1A. Risk Factors,” for a discussion of the risks and uncertainties that affect our business and financial and operating results.

We expect the public and private debt and equity capital markets to serve as another source of liquidity. For example, in June 2011, we completed our IPO for net proceeds of approximately \$173.1 million, and in February 2012, we completed an offering of US\$200 million of Senior Notes for net proceeds of approximately \$192 million. Our ability to access the debt and equity capital markets on economic terms in the future will be affected by general economic conditions, the domestic and global financial markets, credit ratings that may be assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of our equity securities, prevailing commodity prices and other macroeconomic factors outside of our control.

In connection with our IPO, we entered into a tax sharing agreement with Forest, under which, for a two-year period following the Distribution, we will be restricted in our ability, among other things, to divest assets outside the ordinary course of business, to issue or sell our common stock or other securities (including securities convertible into our common stock but excluding certain compensation arrangements) or to enter into any other corporate transaction that would cause us to undergo either a 50% or greater change in the ownership of our voting stock or a 50% or greater change in the ownership (measured by value) of all classes of our stock (in either case, taking into account shares issued in our IPO).

Bank Credit Facility

On March 18, 2011, we entered into a \$500 million credit facility among Lone Pine, as parent, LPR Canada, as borrower, and a syndicate of banks led by JPMorgan Chase Bank, N.A., Toronto Branch. Our bank credit facility became effective upon the closing of our IPO and replaced the existing LPR Canada bank credit facility at such time. Our bank credit facility will mature on March 18, 2016. Availability under our bank credit facility is governed by a borrowing base, which is currently \$375 million. The determination of the borrowing base is made by the lenders, in their sole discretion, taking into consideration the estimated value of LPR Canada’s oil and natural gas properties in accordance with the lenders’ customary practices for oil and gas loans. The borrowing base will be redetermined semi-annually, and the available borrowing amount under our bank credit facility could increase or decrease based on such redetermination. In September 2011, we entered into an amendment to increase the borrowing base from \$350 million to \$425 million, at the first redetermination of the borrowing base. On February 14, 2012, upon completion of our offering of the Senior Notes, our borrowing base was automatically reduced from \$425 million to \$375 million. The next scheduled redetermination of the borrowing base is expected to occur on or about May 1, 2012. In

addition to the scheduled semi-annual redeterminations, we and the lenders each have discretion at any time, but not more often than once during any calendar year, to have the borrowing base redetermined.

The borrowing base is also subject to change in the event (1) Lone Pine or any of its restricted subsidiaries issue senior unsecured notes, in which case the borrowing base will immediately be reduced by an amount equal to 25% of the stated principal amount of such issued senior unsecured notes, excluding any senior unsecured notes that Lone Pine or any of its restricted subsidiaries may issue to refinance then-existing senior notes, (2) LPR Canada divests of oil and natural gas properties included in the borrowing base having a fair market value in excess of 10% of the borrowing base then in effect or (3) if there is a casualty event related to oil and natural gas properties included in the borrowing base. The borrowing base is subject to other automatic adjustments under our bank credit facility. A lowering of the borrowing base could require us to repay indebtedness in excess of the borrowing base in order to cover a deficiency.

Borrowings under our bank credit facility bear interest at one of two rates that we elect. Borrowings bear interest at a rate that may be based on either:

- (1) the sum of the applicable bankers' acceptance rate (as determined in accordance with the terms of our bank credit facility), and a stamping fee of between 175 to 275 basis points, depending on borrowing base utilization; or
- (2) the Canadian Prime Rate (as determined in accordance with the terms of our bank credit facility) plus 75 to 175 basis points, depending on borrowing base utilization.

Our bank credit facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends and mergers and acquisitions and also includes a financial covenant. Our bank credit facility provides that Lone Pine will not permit its ratio of total debt outstanding to consolidated EBITDA (as adjusted for non-cash charges) for a trailing 12-month period to be greater than 4.00 to 1.00. As at December 31, 2011, this ratio was approximately 2.5 to 1.0.

Under certain conditions, amounts outstanding under our bank credit facility may be accelerated. Bankruptcy and insolvency events with respect to Lone Pine, LPR Canada or certain of Lone Pine's or LPR Canada's subsidiaries will result in an automatic acceleration of the indebtedness under our bank credit facility. Subject to notice and cure periods, certain events of default under our bank credit facility will result in acceleration of the indebtedness under the facility at the option of the lenders. Such other events of default include non-payment, breach of warranty, non-performance of obligations under our bank credit facility (including the financial covenant), default on other indebtedness, certain pension plan events, certain adverse judgments, change of control and a failure of the liens securing our bank credit facility.

Our bank credit facility is collateralized by the assets of LPR Canada and certain of its restricted subsidiaries. Under our bank credit facility, LPR Canada is required to mortgage and grant a security interest in 75% of the present value of the proved oil and natural gas properties and related assets of LPR Canada and its restricted subsidiaries. LPR Canada is required to pledge, and has pledged, the stock of its subsidiary to the lenders to secure our bank credit facility. Under certain circumstances, LPR Canada could be obligated to pledge additional assets as collateral. The stock of all of Lone Pine's subsidiaries has been pledged to the lenders to secure our bank credit facility. Lone Pine and certain of its other subsidiaries have guaranteed the obligations of LPR Canada under our bank credit facility.

Of the \$500 million total nominal amount under our bank credit facility, JPMorgan Chase Bank, N.A., Toronto Branch and 10 other banks hold 100% of the total commitments, with JPMorgan Chase, N.A., Toronto Branch holding 13.3% of the total commitments, two lenders holding 11.7% each of the

total commitments, three lenders holding 10% each of the total commitments and the other lenders holding 6.7% each of the total commitments.

From time to time, we and our affiliates have engaged or may engage in other transactions with a number of the lenders under our bank credit facility. Such lenders or their affiliates have served as underwriters in connection with our IPO or initial purchasers in connection with our offering of the Senior Notes, serve as counterparties to LPR Canada's commodity derivative agreements and may, in the future, act as agent or directly purchase LPR Canada's production.

Senior Notes

In February 2012, our wholly-owned subsidiary, LPR Canada, issued the Senior Notes, which mature in February 2017. The net proceeds of approximately \$192 million, after deduction of original issue and initial purchaser discounts and estimated offering expenses, were used to partially repay borrowings outstanding under our bank credit facility. The Senior Notes are guaranteed by Lone Pine and all of its wholly-owned subsidiaries (other than LPR Canada).

Working Capital Deficit

We had a working capital deficit of approximately \$30.1 million at December 31, 2011, primarily due to an increase in accounts payable related to our capital program.

Historical Cash Flow

Net cash provided by operating activities, net cash (used in)/provided by investing activities and net cash provided by/(used in) financing activities for the years ended December 31, 2011, 2010 and 2009 were as follows:

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Net cash provided by operating activities	\$ 120,823	\$ 87,381	\$ 54,480
Net cash (used in)/provided by investing activities .	(337,593)	(225,155)	21,712
Net cash provided by/(used in) financing activities	216,093	128,945	(66,790)

Net cash provided by operating activities is primarily affected by sales volumes and commodity prices. The increase in net cash provided by operating activities in 2011 compared to 2010, was primarily due to higher production volumes and liquids prices partially offset by lower natural gas prices. The increase from 2010 compared to 2009 was primarily due to higher commodity prices.

Net cash (used in)/provided by investing activities is primarily comprised of the exploration and development of oil and natural gas properties, net of the divestiture of oil and natural gas properties. The components of net cash (used in)/provided by investing activities were as follows:

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Exploration and development of oil and natural gas properties and leasehold acquisitions(1) . .	\$(325,095)	\$(208,869)	\$(105,897)
Other fixed assets	(12,841)	(44,310)	(456)
Proceeds from divestiture of assets	343	28,024	128,065
Net cash (used in)/provided by investing activities	<u>\$(337,593)</u>	<u>\$(225,155)</u>	<u>\$ 21,712</u>

- (1) Cash paid for exploration and development costs and leasehold acquisitions as reflected in the consolidated statements of cash flows differs from the reported capital expenditures in the “Capital Expenditures” table due to the timing of when the capital expenditures are incurred and when the actual cash payment is made.

The increase in net cash used by investing activities in 2011 compared to 2010 was due to the acquisition of additional interests in the Narraway/Ojay area and increased exploration and development expenditures in the Evi and Narraway/Ojay areas. There were no significant proceeds from the divestiture of non-core assets in 2011. The increase in net cash used by investing activities for 2010 compared to 2009 was primarily due to an increase in exploration and development of oil and natural gas properties, leasehold acquisitions and other fixed assets, partially offset by a decrease in proceeds from the divestiture of non-core assets. The remaining increase was primarily associated with an increase in drilling activities in the Narraway/Ojay fields and the Evi area and the installation of gathering infrastructure in the Narraway/Ojay fields. Net cash provided by investing activities in 2009 included significant proceeds from the divestiture of non-core oil and natural gas properties that primarily occurred during the fourth quarter of 2009, partially offset by cash used in exploration and development activities. See “—*Capital Expenditures*” below for more detail on our capital expenditures.

Net cash provided by/(used in) financing activities was as follows:

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Proceeds from bank borrowings	\$ 2,531,000	\$ 151,000	\$ 145,000
Repayments of bank borrowings	(2,200,000)	(151,000)	(260,000)
Repayments to Forest Oil Corporation	(368,385)	(1,264)	(2,904)
Proceeds from Forest Oil Corporation	106,512	128,703	51,369
Cash distribution to Forest Oil Corporation	(28,711)	—	—
Proceeds from issuance of common stock, net of offering costs . .	173,086	—	—
Change in bank overdrafts	440	1,566	(206)
Proceeds from sale-leaseback, net of repayments	6,894	—	—
Costs related to bank credit facility	(4,700)	—	—
Other, net	(43)	(60)	(49)
Net cash provided by/(used in) financing activities	<u>\$ 216,093</u>	<u>\$ 128,945</u>	<u>\$ (66,790)</u>

Net cash provided by financing activities for 2011 was primarily derived from net proceeds from the issuance of common stock in our IPO and bank borrowings, both of which were used to repay amounts owing to Forest. Net cash provided by financing activities for 2010 was primarily comprised of borrowings from Forest. Net cash used in financing activities for 2009 included net repayments of our bank credit facility, offset somewhat by borrowings from Forest.

Capital Expenditures

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Acquisition, exploration, development and leasehold acquisition costs:			
Property acquisition costs:			
Proved properties	\$ 48,362	—	—
Unproved properties	38,823	41,037	12,215
Exploration costs	24,809	8,791	29,529
Development costs	233,653	159,057	55,896
Total capital expenditures(1)	<u>\$345,647</u>	<u>\$208,885</u>	<u>\$97,640</u>

(1) Total capital expenditures include cash and accrued expenditures. Total capital expenditures also include changes in estimated discounted asset retirement obligations of \$1.0 million, (\$1.1) million, and (\$1.8) million recorded during the years ended December 31, 2011, 2010 and 2009, respectively.

Primary factors impacting the level of our capital expenditures include oil, natural gas and NGL prices, the volatility in these prices, the cost and availability of field services, general economic and market conditions and weather disruptions. Due to the downturn in the global economy in late 2008 and the resulting negative impact on the price for oil, natural gas and NGLs, we chose to significantly reduce our capital expenditures and drilling activity in 2009. As a result of significantly increased liquidity in 2010 due to non-core oil and natural gas property divestitures, higher oil and NGL prices and focusing our development primarily on our core areas with expected high growth potential, we increased our drilling activity in 2010. In 2011, we acquired additional interests in the Narraway/Ojay area for \$74.4 million and also continued to increase our drilling activity with a focus on light oil development projects.

We have established a capital budget of approximately \$200 million to \$220 million for 2012 and plan to focus our drilling program almost entirely on our light oil opportunities in the Evi area. See “—Capital Budget for 2012.”

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2011:

	2012	2013	2014	2015	2016	After 2016	Total
	(In thousands)						
Bank credit facility(1)	\$13,067	\$13,032	\$13,032	\$13,032	\$333,749	—	\$385,912
Amounts due to Forest(2)	252	—	—	—	—	—	252
Operating leases(3)	1,631	1,748	1,745	1,696	1,679	8,822	17,321
Capital lease(4)	1,476	1,476	1,476	1,476	1,914	—	7,818
Unconditional purchase obligations(5)	6,334	2,926	167	64	—	—	9,491
Other liabilities(6)	61	61	62	65	68	15,020	15,337
Total contractual obligations	<u>\$22,821</u>	<u>\$19,243</u>	<u>\$16,482</u>	<u>\$16,333</u>	<u>\$337,410</u>	<u>\$23,842</u>	<u>\$436,131</u>

(1) Bank credit facility amounts include the anticipated interest payments and commitment fees due under the terms of our bank credit facility using the interest rate in effect, borrowings outstanding and the borrowing base at December 31, 2011. Our bank credit facility matures in March 2016.

- (2) Amounts due to Forest include amounts related to the transition services agreement with Forest, which terminated on December 1, 2011.
- (3) Operating leases consist of leases for office facilities and equipment and vehicles.
- (4) Our capital lease is for compressors and surface equipment.
- (5) Unconditional purchase obligations consist of firm transportation commitments.
- (6) Other liabilities are comprised of postretirement benefit obligations and asset retirement obligations, for which neither the timing nor the amount of ultimate settlement can be precisely determined in advance. See “—Critical Accounting Policies, Estimates, Judgments and Assumptions” below for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

Off-Balance Sheet Arrangements

From time to time, we enter into off-balance sheet arrangements and other transactions that can give rise to off-balance sheet obligations. As of December 31, 2011, the off-balance sheet arrangements and other transactions that we have entered into include (1) operating lease agreements, (2) firm transportation commitments and (3) other contractual obligations for which we have recorded estimated liabilities on the balance sheet, but the ultimate settlement amounts are not fixed and determinable, such as ARO and postretirement benefit obligations. We do not believe that any of these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

Critical Accounting Policies, Estimates, Judgments and Assumptions

Change in Reporting and Functional Currency

Reporting Currency

Our consolidated financial statements for previous periods were reported using the U.S. dollar, as this was the reporting currency used by Forest. Effective October 1, 2011, Lone Pine changed its reporting currency to the Canadian dollar to better reflect the business of Lone Pine, which is almost entirely conducted in Canadian dollars. This change in reporting currency was also considered appropriate since there were only two major financial statement categories denominated in U.S. dollars. One category was the liability to Forest, including Advances, accrued interest and the Note payable (for periods prior to June 1, 2011) and the second category was the Stockholders' Equity of Lone Pine (for periods after the IPO date of June 1, 2011).

With the change in reporting currency, all comparative financial information has been recast from U.S. dollars to Canadian dollars to reflect our consolidated financial statements as if they had been historically reported in Canadian dollars, consistent with ASC 830, *Foreign Currency Matters*.

The consolidated U.S. dollar balance sheet at December 31, 2010 was translated into the Canadian dollar reporting currency by translating assets and liabilities at the end-of-period exchange rate and translating equity balances at historical exchange rates. The consolidated statement of operations was translated into Canadian dollars using the weighted average exchange rate for the period. The resulting foreign currency translation adjustment is reported as a component of other comprehensive income and accumulated other comprehensive income.

Functional Currency

We changed the functional currency of Lone Pine prospectively from October 1, 2011 from the U.S. dollar to the Canadian dollar. The change in functional currency did not have a significant impact

on our consolidated financial statements for either the fourth quarter of 2011 or the year ended December 31, 2011 as Lone Pine's operations are primarily carried out by its operating subsidiary, LPR Canada. The functional currency of LPR Canada has not changed and continues to be the Canadian dollar. As a result of this change in functional currency, there is no difference between the reporting currency and the functional currency of Lone Pine and any of its subsidiaries.

U.S. Dollar Financial Information for 2011

In order for our stockholders to better understand the transition to Canadian dollars, the following table provides selected financial information in U.S. dollars and Canadian dollars as of and for the year ended December 31, 2011.

	US\$	Cdn\$
	(In thousands)	
Statement of operations for the year ended December 31, 2011		
Total revenues	193,551	191,200
Lease operating expenses	39,223	38,789
Production and property taxes	2,372	2,337
Transportation and processing	17,480	17,252
General and administrative	13,235	13,115
Depreciation, depletion and amortization	86,815	85,751
Interest expense	10,135	10,034
Foreign currency exchange losses (gains)	(5,357)	(4,976)
Losses (gains) on derivative instruments	(27,252)	(28,167)
Other, net	4,484	4,538
Total costs, expenses, and other	141,135	138,673
Earnings before income taxes	52,416	52,527
Income tax	17,827	17,724
Net earnings	34,589	34,803
Basic and diluted earnings per share	0.44	0.44
Balance sheet at December 31, 2011		
Current assets	53,517	54,426
Non-current assets	922,213	937,875
Current liabilities	83,079	84,490
Bank credit facility	325,472	331,000
Other non-current liabilities	91,397	92,949
Total stockholders' equity	475,782	483,862
Statement of cash flows for the year ended December 31, 2011		
Net cash provided by operating activities	121,690	120,823
Net cash used in investing activities	(344,765)	(337,593)
Net cash provided by financing activities	222,538	216,093

Basis of Presentation

The consolidated financial statements relating to the periods prior to our inception (September 30, 2010) reflect the financial position, results of operations, cash flows or other information, as the case may be, of our predecessor, LPR Canada. The consolidated financial statements relating to the period from our inception through the completion of our IPO (June 1, 2011) reflect the financial position, results of operations, cash flows or other information, as the case may be, of Lone Pine and its predecessor, LPR Canada, on a combined basis. The consolidated financial statements relating to the

period subsequent to and including June 1, 2011 reflect the financial position, results of operations, cash flows or other information, as the case may be, of Lone Pine and its wholly-owned consolidated subsidiaries.

Full Cost Method of Accounting

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 full cost method and the successful efforts method. The differences between the two methods can lead to significant variances in the amounts reported in financial statements. We have elected to follow the full cost method, which is described below.

Since we operate in one country, under the full cost method, we maintain one cost center. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, dry holes and overhead directly related to exploration and development activities) are capitalized to this cost center. The fair value of estimated future costs of site restoration, dismantlement and abandonment activities is capitalized, and a corresponding ARO liability is recorded.

Costs capitalized to the full cost center are depleted using the units-of-production method, based on conversion to common units of measure, using one barrel of oil as an equivalent to six thousand cubic feet of natural gas. Historically, we have prospectively updated our quarterly depletion calculations with the changes in our reserve estimates and future development costs. Based on this accounting policy, our December 31, 2011 reserve estimates were used for our fourth quarter 2011 depletion calculation. However, in future, we will only adjust the depletion rate for quarterly purposes in the event of significant changes to the calculation, such as a significant increase or decrease in the volume of proved reserves. See Part I, “Item 1. Business—Reserves” and the notes to the consolidated financial statements of LPR Canada included in this Form 10-K for more information regarding our estimated proved reserves as of December 31, 2011, 2010 and 2009.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test each quarter for each cost center. The full cost ceiling test is a limitation on capitalized costs prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is not a fair value-based measurement. Rather, it is a standardized mathematical calculation. The test determines a limit, or ceiling, on the book value of oil and natural gas properties. That limit is basically the after tax present value of the future net cash flows from proved oil and natural gas reserves. This ceiling is compared to the net book value of the oil and natural gas properties, reduced by any related net deferred income tax liability. If the net book value reduced by the related deferred income taxes exceeds the ceiling, an impairment or non-cash write-down is required. We recorded a \$251.0 million non-cash ceiling test write-down in the first quarter of 2009. We did not incur any additional ceiling test write-downs from March 31, 2009 through December 31, 2011. Our ceiling test calculations have been based on the 12-month average natural gas and oil prices since December 31, 2009.

In areas where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs and other costs incurred during the exploration phase remain capitalized as unproved property costs until proved reserves have been established or until exploration activities cease. Investments in unproved properties are not depleted, pending the determination of the existence of proved reserves. If exploration activities result in the establishment of proved reserves, amounts are reclassified as proved properties and become subject to DD&A, and the application of the ceiling limitation. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties and geographic and geologic

data obtained relating to the properties. Where it is not practicable to individually assess properties whose costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized in the full cost pool.

Under the alternative successful efforts method of accounting, surrendered, abandoned and impaired leases, delay lease rentals, exploratory dry holes and overhead costs are expensed as incurred. Capitalized costs are depleted on a property-by-property basis. Impairments are also assessed on a property-by-property basis and are charged to expense when assessed.

The full cost method is used to account for our oil and natural gas exploration and development activities because we believe it appropriately reports the costs of our exploration programs as part of an overall investment in discovering and developing proved reserves.

Goodwill

Goodwill is not subject to amortization, and therefore we perform an annual impairment assessment, which was performed at December 31, 2011. In addition, we test goodwill for impairment if events or circumstances change between annual tests indicating a possible impairment.

In the first step of testing for goodwill impairment, we estimate the fair value of the reporting unit and compare the fair value with the carrying value of the net assets of the reporting unit. If the fair value of the reporting unit is greater than the carrying value of the net assets of the reporting unit, then no impairment results. If the fair value is less than its carrying value, then we would perform a second step and determine the fair value of the goodwill. In this second step, the fair value of goodwill is determined by deducting the fair value of the reporting unit's identifiable assets and liabilities from the fair value of the reporting unit as a whole, as if that reporting unit had just been acquired and the purchase price were being initially allocated. If the fair value of the goodwill is less than its carrying value for a reporting unit, an impairment charge would be recorded to earnings in our consolidated statement of operations.

To determine the fair value of the reporting unit, we use a discounted cash flow model to value our total estimated reserves, which include proved, probable and possible reserves. This approach relies on significant judgments about the quantity of reserves, the timing of the expected production, the pricing that will be in effect at the time of production and the appropriate discount rates to be used. Our discount rate assumptions are based on an assessment of our weighted average cost of capital.

We did not record an impairment charge as a result of our goodwill impairment tests that we performed at December 31, 2011. However, due to the significant judgments that go into the test, as discussed above, there can be no assurance that our goodwill will not be impaired at any time in the future.

Oil and Gas Reserve Estimates

Our estimates of proved reserves are based on the quantities of oil and natural gas that geoscience and engineering data demonstrate, with reasonable certainty, to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations, prior to the time at which contracts providing the right to operate expire. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate the amount and timing of future operating costs, production and property taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the

inherent uncertainty in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and natural gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and natural gas properties are also subject to a “ceiling test” limitation, based in part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and natural gas disclosures included in note 25 to our consolidated financial statements contained elsewhere in this Form 10-K.

Asset Retirement Obligations

We have obligations to remove tangible equipment and restore locations at the end of the oil and natural gas production operations. Estimating the future restoration and removal costs, or ARO, is difficult and requires management to make estimates and judgments, because most of the obligations are many years in the future, and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the calculation of the present value of our ARO are numerous assumptions and judgments, including the ultimate settlement amounts, 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 present value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance. Increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense in our consolidated statements of operations.

Fair Value of Derivative Instruments

We use the income approach in determining the fair value of our derivative instruments, utilizing present value techniques for valuing our swaps and option-pricing models for valuing our collars, swaptions, puts and calls. Inputs to these valuation techniques include published forward prices, volatilities and credit risk considerations, including the incorporation of published interest rates and credit spreads. The values we report in our financial statements change as these estimates are revised to reflect changes in market conditions or other factors, many of which are beyond our control.

The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the consolidated statement of operations, because changes in fair value of the derivative offset changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings as other income or expense.

We have elected not to use hedge accounting to account for our derivative instruments and, as a result, all changes in the fair values of our derivative instruments are recognized in earnings as unrealized gains or losses in our consolidated statements of operations.

Due to the volatility of oil and natural gas prices and interest rates, the estimated fair values of our derivative instruments are subject to large fluctuations from period to period. See Part II, “Item 7A. Quantitative and Qualitative Disclosures about Market Risk” for a sensitivity analysis of the change in net fair values of our commodity derivatives based on a hypothetical change in commodity prices.

Recent Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2011-04, *Fair Value Measurement, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (“ASU 2011-04”), which amends the current GAAP fair value measurement and disclosure guidance, to converge GAAP and IFRS requirements for measuring amounts at fair value as well as disclosures about these measurements. Many of the amendments clarify existing concepts and are not expected to result in significant changes to how companies apply the fair value principles. This authoritative guidance is effective for interim and annual periods beginning after December 15, 2011. We are currently evaluating the impact that the adoption of this authoritative guidance will have on our consolidated financial statements.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, *Intangibles—Goodwill and Other (Topic 350), Testing Goodwill for Impairment*, which permits entities to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount to determine whether it is necessary to perform the two-step goodwill impairment test. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. However, if an entity concludes otherwise, it is required to perform the first step of the two-step impairment test, which may then lead an entity to performing the second step as well. Entities have the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to the first step of the two-step impairment test. This authoritative guidance is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of this authoritative accounting guidance may change the methodology that we use to test our goodwill for impairment depending on the events or circumstances at the time the test is performed.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, *Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities* (“ASU 2011-11”), which requires that an entity disclose both gross and net information about instruments and transactions that are either eligible for offset in the balance sheet or subject to an agreement similar to a master netting agreement, including derivative instruments. ASU 2011-11 was issued in order to facilitate comparison between GAAP and IFRS financial statements by requiring enhanced disclosures, but does not change existing GAAP that permits balance sheet offsetting. This authoritative guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. We are currently evaluating the impact that the adoption of this authoritative guidance will have on our consolidated financial statements.

In December 2011, the FASB issued Accounting Standards Update No. 2011-12, *Comprehensive Income, Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05* (“ASU 2011-12”), which indefinitely defers the requirements in adopted Accounting Standards Update No. 2011-05, *Comprehensive Income, Presentation of Comprehensive Income* (“ASU 2011-05”) to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income (see note 4 to our consolidated financial statements for additional information). The adoption of this authoritative guidance will not have an impact on our consolidated financial statements until the specific changes that were proposed under ASU 2011-05 are finalized and issued by the FASB.

Adoption of New Accounting Standards

In the fourth quarter of 2011, we early adopted ASU 2011-05, except for the specific changes that have been deferred under ASU 2011-12, as noted above. The adoption of ASU 2011-05 required that

we present items of net income, items of other comprehensive income and total comprehensive income either in a single continuous statement or in two separate consecutive statements and eliminated the option to report other comprehensive income and its components in the statement of stockholders' equity. We elected to present two separate consecutive statements. Other than a change in presentation, the adoption of ASU 2011-05 did not have any impact on our consolidated financial statements.

In 2011, we adopted Accounting Standards Update No. 2010-29, "*Business Combinations (Topic 805)—Disclosure of Supplementary Pro Forma Information for Business Combinations*," which updated the current authoritative guidance pertaining to the disclosure requirements for a business combination. Other than requiring additional pro forma revenue and earnings disclosure related to a business combination, the adoption of ASU 2010-29 did not have any impact on our consolidated financial statements.

Reconciliation of Non-GAAP Measures

In addition to reporting net earnings as defined under GAAP, we also present Adjusted EBITDA, which is calculated as net earnings (loss) plus interest expense, income tax expense (benefit), DD&A, impairment of assets, ceiling test write-downs of oil and natural gas properties, accretion of asset retirement obligations, unrealized losses (gains) on derivative instruments and foreign currency exchange (gains) losses and is a non-GAAP measure. Adjusted EBITDA also excludes the equity-accounted for portion of stock-based compensation expense, as these amounts will be settled in shares of our common stock rather than cash payments. By eliminating these items, we believe the result is a useful measure across time in evaluating our fundamental core operating performance. Our management also uses Adjusted EBITDA to manage our business, including in preparing our annual operating budget and financial projections. We believe that Adjusted EBITDA is also useful to investors because similar measures are frequently used by securities analysts, investors and other interested parties in their evaluation of companies in similar industries. As indicated, Adjusted EBITDA does not include interest expense on borrowed money, depletion, depreciation and amortization expense on capital assets or the payment of income taxes, which are all necessary elements of our operations. Because Adjusted EBITDA does not account for these and other expenses, its utility as a measure of our operating performance has material limitations. Because of these limitations, our management does not view Adjusted EBITDA in isolation and also uses other measurements, such as net earnings and revenues, to measure operating performance.

In addition to reporting cash provided by operating activities as defined under GAAP, we also present Adjusted Discretionary Cash Flow, which is a non-GAAP liquidity measure. Adjusted Discretionary Cash Flow consists of cash provided by operating activities before changes in working capital items. Management uses Adjusted Discretionary Cash Flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operating activities for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. This measure does not represent the residual cash flow available for discretionary expenditures, since we have mandatory debt service requirements and other non-discretionary expenditures that are not deducted from the measure. Because of this, its utility as a measure of our operating performance has material limitations.

The following table reconciles Adjusted EBITDA to net earnings (loss), which is the most directly comparable financial measure calculated and presented in accordance with GAAP.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Net earnings (loss):	\$ 34,803	\$ 32,825	(177,746)
Add back (deduct):			
Interest expense	10,034	7,190	18,466
Income tax expense (benefit)	17,724	7,911	(63,066)
Depreciation, depletion, and amortization (including amortization of deferred costs)	86,846	66,222	64,843
Impairment of inventory	2,262	—	—
Ceiling test write-down of oil and natural gas properties	—	—	251,035
Accretion of asset retirement obligations	1,071	1,073	1,143
Unrealized losses (gains) on derivative instruments	(19,786)	—	—
Foreign currency exchange (gains) losses	(4,976)	(13,924)	(18,932)
Stock-based compensation	269	—	—
Adjusted EBITDA	<u>\$128,247</u>	<u>\$101,297</u>	<u>\$ 75,743</u>

The following table reconciles Adjusted Discretionary Cash Flow to cash provided by operating activities, which is the most directly comparable financial measure calculated and presented in accordance with GAAP.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Net cash provided by operating activities	\$120,823	\$87,381	\$54,480
Changes in working capital:			
Accounts receivable	(4,322)	10,747	(8,750)
Prepaid expenses and other current assets	(3,005)	4,111	2,591
Accounts payable and accrued liabilities	(19,284)	732	13,874
Accrued interest and other current liabilities	24,198	(8,723)	(4,801)
Adjusted discretionary cash flow	<u>\$118,410</u>	<u>\$94,248</u>	<u>\$57,394</u>

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

We are exposed to market risk, including the effects of adverse changes in commodity prices, interest rates and foreign currency exchange rates as discussed below.

Commodity Price Risk

We produce and sell natural gas, crude oil and NGLs. As a result, our financial results are affected when prices for these commodities fluctuate, and the effects can be significant. We enter into commodity swap derivative instruments to manage our exposure to commodity price risk caused by fluctuations in commodity prices, which protects and provides certainty on a portion of our cash flows. Under this strategy, we enter into contracts with counterparties who are participants in our bank credit facility. These arrangements, which are based on prices available in the financial markets at the time the contracts are entered into, are settled in cash and do not require physical deliveries of hydrocarbons.

Long-Term Sales Contract

As of March 20, 2012, we had a delivery commitment of approximately 21,000 MMBtu/d of natural gas, which provides for a price equal to the greater of (1) the NYMEX Henry Hub price less US\$1.49 and (2) US\$1.00 per MMBtu to a buyer through October 31, 2014, unless the NYMEX Henry Hub price exceeds US\$6.50 per MMBtu, at which point we share the amount of the excess equally with the buyer.

Swaps

In a typical commodity swap agreement, we receive the difference between a fixed price per unit of production and a price based on an agreed upon published, third-party index if the index price is lower than the fixed price. If the index price is higher, we pay the difference. By entering into swap agreements, we effectively fix the price that we will receive in the future for the hedged production. Our current swaps are settled in cash on a monthly basis. As of December 31, 2011, we had entered into the following swaps:

Swap Term	Commodity Swaps			
	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	MMBtu/d	Weighted Average Hedged Price per MMBtu	bbl/d	Weighted Average Hedged Price per bbl
Calendar 2012	25,000	US\$5.09	2,000	US\$102.35
Calendar 2012	—	—	1,000	\$100.98

The estimated fair value of all our commodity derivative instruments based on various inputs, including published forward prices, at December 31, 2011 was an asset of approximately \$19.8 million.

Due to the volatility of oil, natural gas and NGL prices, the estimated fair values of our commodity derivative instruments are subject to large fluctuations from period to period. For example, a hypothetical 10% increase in the forward oil, natural gas and NGL prices used to calculate the fair values of our commodity derivative instruments at December 31, 2011 would have decreased the net fair value of our commodity derivative instruments at December 31, 2011 by approximately \$14.0 million. It has been our experience that commodity prices are subject to large fluctuations, and we expect this volatility to continue. Actual gains or losses recognized related to our commodity derivative instruments will likely differ from those estimated at December 31, 2011 and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

The table below sets forth the changes that occurred in the fair values of our derivative contracts during the year ended December 31, 2011.

	Fair Value of Derivative Contracts
	(in thousands)
As of December 31, 2010	\$ —
Net change in fair value	28,167
Net gains realized	(8,381)
As of December 31, 2011	<u>\$19,786</u>

The following table summarizes additional commodity swaps that were entered into between the period January 1, 2012 to March 20, 2012:

Swap Term	Commodity Swaps			
	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	MMBtu/d	Weighted Average Hedged Price per MMBtu	bbl/d	Weighted Average Hedged Price per bbl
Calendar 2013	—	—	500	\$102.00
Calendar 2013	—	—	500	US\$101.00

Interest Rate Risk

At December 31, 2011, we had \$331.0 million in outstanding borrowings on our bank credit facility, and the weighted average interest rate on the facility was 3.7603%. Given that the interest rate on the facility is based on market rates for interest, we are exposed to interest rate risk on these borrowings. We have not entered into any derivative financial instruments to manage this risk.

We do not have any exposure to interest rate risk on the Senior Notes, given that the interest rate is fixed for the term of the Senior Notes. However, we are exposed to foreign currency exchange risk on the actual interest payments since these payments will be made in U.S. dollars.

Foreign Currency Exchange Rate Risk

As discussed above, the Canadian dollar is both our functional and reporting currency, and therefore our foreign currency exchange rate risk has been significantly reduced. Our most significant foreign currency exchange rate risk relates to the Senior Notes since they are denominated in U.S. dollars, and we are exposed to currency exchange rate risk on the translation and repayment of this debt as well as the interest payments every six months. We have not entered into any foreign currency forward contracts or other similar financial instruments to manage this risk. We are also exposed to foreign currency exchange rate risk relating to certain of our derivative instruments and our delivery commitment of approximately 21,000 MMBtu/d of natural gas under a long-term sales contract expiring in 2014.

Item 8. Financial Statements and Supplementary Data.**Index to Consolidated Financial Statements**

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Report of Independent Registered Public Accounting Firm

To The Board of Directors and Stockholders of Lone Pine Resources Inc.

We have audited the accompanying consolidated balance sheet of Lone Pine Resources Inc. and subsidiaries (the “Company”) as of December 31, 2011, and the related consolidated statements of operations, comprehensive income, cash flows and stockholders’ equity for the year then ended. These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company’s 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, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Lone Pine Resources Inc. and subsidiaries at December 31, 2011, and the consolidated results of its operations and its cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Calgary, Alberta
March 22, 2012

Report of Independent Registered Public Accounting Firm

To The Board of Directors and Stockholders of Lone Pine Resources Inc.

We have audited the accompanying consolidated balance sheet of Lone Pine Resources Inc. and subsidiaries as of December 31, 2010, and the related consolidated statements of operations, comprehensive income, cash flows and stockholders' equity for each of the two years in the period ended December 31, 2010. 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits 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, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Lone Pine Resources Inc. and subsidiaries at December 31, 2010, and the consolidated results of its operations and its cash flows for each of the two years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 3 to the consolidated financial statements, effective December 31, 2009, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

/s/ Ernst & Young LLP
Denver, Colorado
March 22, 2012

LONE PINE RESOURCES INC.
CONSOLIDATED BALANCE SHEETS
(In thousands of Canadian dollars)

	December 31, 2011	December 31, 2010 (Recast*)
ASSETS		
Current assets:		
Cash	\$ 276	\$ 573
Accounts receivable	28,804	33,226
Derivative instruments	19,786	—
Prepaid expenses and other current assets	5,560	6,136
Total current assets	54,426	39,935
Property and equipment, at cost:		
Oil and natural gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of \$1,203,755 and \$1,119,437	704,232	476,229
Unproved	138,727	105,744
Net oil and natural gas properties	842,959	581,973
Other property and equipment, net of accumulated depreciation and amortization of \$8,647 and \$8,016	66,413	59,966
Net property and equipment	909,372	641,939
Goodwill	17,328	17,328
Other assets	11,175	12,149
	<u>\$ 992,301</u>	<u>\$711,351</u>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 75,450	\$ 41,976
Advances and accrued interest payable to Forest Oil Corporation	252	38,830
Note payable to Forest Oil Corporation	—	248,839
Capital lease obligation	1,156	—
Deferred income taxes	4,946	—
Other current liabilities	2,686	3,427
Total current liabilities	84,490	333,072
Bank credit facility	331,000	—
Asset retirement obligations	15,412	13,667
Deferred income taxes	69,981	57,251
Capital lease obligation	5,738	—
Other liabilities	1,818	3,617
Total liabilities	508,439	407,607
Stockholders' equity:		
Common stock, 85,026,202 and 2,107 shares issued and outstanding	833	—
Capital surplus	978,880	267,260
Retained earnings (accumulated deficit)	(495,959)	36,594
Accumulated other comprehensive income (loss)	108	(110)
Total stockholders' equity	483,862	303,744
	<u>\$ 992,301</u>	<u>\$711,351</u>

* see notes 1 and 2

See accompanying notes to consolidated financial statements.

LONE PINE RESOURCES INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands of Canadian dollars)

	Year Ended December 31,		
	2011	2010	2009
		(Recast*)	(Recast*)
Revenues:			
Oil and natural gas sales	\$191,170	\$151,184	\$ 127,396
Interest and other	30	24	(187)
Total revenues	191,200	151,208	127,209
Costs, expenses and other:			
Lease operating expenses	38,789	26,547	31,255
Production and property taxes	2,337	2,513	3,165
Transportation and processing	17,252	11,104	9,197
General and administrative	13,115	9,590	7,969
Depreciation, depletion and amortization	85,751	65,811	64,358
Ceiling test write-down of oil and natural gas properties	—	—	251,035
Interest expense on borrowings from Forest Oil Corporation	2,857	6,753	15,754
Interest expense	7,177	437	2,712
Foreign currency exchange losses (gains)	(4,976)	(13,924)	(18,932)
Losses (gains) on derivative instruments	(28,167)	—	—
Other, net	4,538	1,641	1,508
Total costs, expenses and other	138,673	110,472	368,021
Earnings (loss) before income taxes	52,527	40,736	(240,812)
Income tax	17,724	7,911	(63,066)
Net earnings (loss)	\$ 34,803	\$ 32,825	\$(177,746)
Basic earnings (loss) per common share	\$ 0.44	\$ 0.47	\$ (2.54)
Diluted earnings (loss) per common share	\$ 0.44	\$ 0.47	\$ (2.54)

* see notes 1 and 2

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands of Canadian dollars)

	Year Ended December 31,		
	2011	2010	2009
		(Recast*)	(Recast*)
Net earnings (loss)	\$34,803	\$32,825	\$(177,746)
Other comprehensive income (loss)			
Foreign currency translation adjustments, net of tax	361	44	—
Minimum postretirement benefits liability adjustment, net of tax	(143)	192	45
	218	236	45
Comprehensive income (loss)	\$35,021	\$33,061	\$(177,701)

* see notes 1 and 2

See accompanying notes to consolidated financial statements.

LONE PINE RESOURCES INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands of Canadian dollars)

	Year Ended December 31,		
	2011	2010	2009
		(Recast*)	(Recast*)
Operating activities:			
Net earnings (loss)	\$ 34,803	\$ 32,825	\$(177,746)
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation, depletion and amortization	85,751	65,811	64,358
Amortization of deferred costs	1,095	411	485
Ceiling test write-down of oil and natural gas properties	—	—	251,035
Deferred income tax	17,724	7,911	(63,066)
Unrealized losses (gains) on derivative instruments	(19,786)	—	—
Unrealized foreign currency exchange losses (gains)	(4,976)	(13,655)	(18,839)
Other, net	3,799	945	1,167
Changes in operating assets and liabilities:			
Accounts receivable	4,322	(10,747)	8,750
Prepaid expenses and other current assets	3,005	(4,111)	(2,591)
Accounts payable and accrued liabilities	19,284	(732)	(13,874)
Accrued interest and other current liabilities	(24,198)	8,723	4,801
Net cash provided by operating activities	120,823	87,381	54,480
Investing activities:			
Capital expenditures for property and equipment:			
Exploration, development and acquisition costs	(325,095)	(208,869)	(105,897)
Other fixed assets	(12,841)	(44,310)	(456)
Proceeds from divestiture of assets	343	28,024	128,065
Net cash (used in) provided by investing activities	(337,593)	(225,155)	21,712
Financing activities:			
Proceeds from bank borrowings	2,531,000	151,000	145,000
Repayments of bank borrowings	(2,200,000)	(151,000)	(260,000)
Repayments to Forest Oil Corporation	(368,385)	(1,264)	(2,904)
Proceeds from Forest Oil Corporation	106,512	128,703	51,369
Cash distribution to Forest Oil Corporation	(28,711)	—	—
Proceeds from issuance of common stock, net of offering costs	173,086	—	—
Change in bank overdrafts	440	1,566	(206)
Proceeds from sale-leaseback, net of repayments	6,894	—	—
Costs related to bank credit facility	(4,700)	—	—
Other, net	(43)	(60)	(49)
Net cash provided by (used in) financing activities	216,093	128,945	(66,790)
Effect of exchange rate changes on cash	380	—	—
Net increase (decrease) in cash	(297)	(8,829)	9,402
Cash at beginning of year	573	9,402	—
Cash at end of year	\$ 276	\$ 573	\$ 9,402
Supplemental cash flow disclosures:			
Interest paid during the year	\$ 7,723	\$ 479	\$ 2,448
Interest paid during the year on borrowings from Forest Oil Corporation	23,359	136	9,891
Income taxes paid during the year	—	—	—
Non-cash working capital related to property and equipment	13,748	4,636	(10,936)

* see notes 1 and 2

See accompanying notes to consolidated financial statements.

LONE PINE RESOURCES INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In thousands of Canadian dollars, except number of shares)

	<u>Common Stock</u>		<u>Capital Surplus</u>	<u>Retained Earnings (Accumulated Deficit)</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total Stockholders' Equity</u>
	<u>Shares</u>	<u>Amount</u>				
	<u>(In thousands)</u>					
Balances at December 31, 2008 (Recast*)	2	\$ —	\$267,260	\$ 181,515	\$(391)	\$ 448,384
Comprehensive income (loss):						
Net earnings (loss)	—	—	—	(177,746)	—	(177,746)
Other comprehensive income	—	—	—	—	45	45
Balances at December 31, 2009 (Recast*)	2	—	267,260	3,769	(346)	270,683
Comprehensive income (loss):						
Net earnings (loss)	—	—	—	32,825	—	32,825
Other comprehensive income	—	—	—	—	236	236
Balances at December 31, 2010 (Recast*)	2	—	267,260	36,594	(110)	303,744
Stock dividend to Forest Oil Corporation . .	—	—	567,356	(567,356)	—	—
Stock issued to Forest Oil Corporation for its contribution of its direct and indirect interests in Lone Pine Resources Canada Ltd.	70,000	687	(687)	—	—	—
Elimination of common shares of Lone Pine Resources Canada Ltd.	(2)	—	—	—	—	—
Cash distribution to Forest Oil Corporation .	—	—	(28,711)	—	—	(28,711)
Issuance of common stock, net of offering costs and tax	15,000	146	172,940	—	—	173,086
Capital contribution from Forest Oil Corporation	—	—	414	—	—	414
Restricted stock issued (net of forfeitures) . .	26	—	—	—	—	—
Amortization of stock-based compensation .	—	—	308	—	—	308
Comprehensive income (loss):						
Net earnings (loss)	—	—	—	34,803	—	34,803
Other comprehensive income	—	—	—	—	218	218
Balances at December 31, 2011	<u>85,026</u>	<u>\$833</u>	<u>\$978,880</u>	<u>\$(495,959)</u>	<u>\$ 108</u>	<u>\$ 483,862</u>

* see notes 1 and 2

See accompanying notes to consolidated financial statements.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND BASIS OF PRESENTATION

Organization

Lone Pine Resources Inc. (“Lone Pine” or the “Company”) is an independent oil and natural gas exploration, development and production company with operations in Canada. Its reserves, producing properties and exploration prospects are located in the provinces of Alberta, British Columbia and Quebec and in the Northwest Territories. Lone Pine was incorporated on September 30, 2010 by Forest Oil Corporation (“Forest”) in contemplation of an initial public offering by Lone Pine (the “IPO”) of Lone Pine’s common stock with Forest subscribing for one share of Lone Pine common stock. Lone Pine’s predecessor, Lone Pine Resources Canada Ltd. (“LPR Canada”), formerly known as Canadian Forest Oil Ltd. (“CFOL”), was a wholly-owned subsidiary of Forest and certain of Forest’s other wholly-owned subsidiaries and was originally acquired by Forest in 1996. Forest contributed its direct and indirect ownership interests in LPR Canada to Lone Pine in conjunction with the IPO in exchange for 69,999,999 shares of common stock of Lone Pine and \$28.7 million in cash. The IPO was completed on June 1, 2011, with Forest retaining a controlling interest in Lone Pine, owning 70 million shares of Lone Pine common stock representing approximately 82% of the outstanding shares of Lone Pine common stock.

On September 30, 2011, Forest paid a special stock dividend to its shareholders of the 70 million shares of common stock of Lone Pine owned by Forest (the “Distribution”).

See note 21 for more information on the IPO and the Distribution.

Basis of Presentation

These financial statements are presented in conformity with U.S. generally accepted accounting principles (“GAAP”). In these consolidated financial statements, unless otherwise indicated, all amounts are expressed in Canadian dollars. Lone Pine conducts operations in one industry segment, liquids and natural gas exploration, development and production, and in one country, Canada.

The consolidated financial statements relating to the periods prior to the inception of Lone Pine (September 30, 2010) reflect the financial position, results of operations, cash flows or other information, as the case may be, of Lone Pine’s predecessor, LPR Canada.

The consolidated financial statements relating to the period from Lone Pine’s inception through the completion of the IPO (June 1, 2011) reflect the financial position, results of operations, cash flows or other information, as the case may be, of Lone Pine and Lone Pine’s predecessor, LPR Canada, on a combined basis.

The consolidated financial statements relating to the period subsequent to and including June 1, 2011 reflects the financial position, results of operations, cash flows or other information, as the case may be, of Lone Pine and its wholly-owned consolidated subsidiaries.

Certain amounts in prior years’ financial statements have been reclassified to conform to the current year’s financial statement presentation.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) CHANGE IN REPORTING AND FUNCTIONAL CURRENCY

Reporting Currency

The Company's consolidated financial statements for previous periods were reported using the U.S. dollar, as this was the reporting currency used by Forest. Effective October 1, 2011, the Company changed its reporting currency to the Canadian dollar to better reflect the business of Lone Pine, which is almost entirely conducted in Canadian dollars. This change in reporting currency was also considered appropriate since there were only two major financial statement categories denominated in U.S. dollars. One category was the liability to Forest, including Advances, accrued interest and the Note payable (for periods prior to June 2011) and the second category was the Stockholders' Equity of Lone Pine (for periods after the IPO date of June 1, 2011).

With the change in reporting currency, all comparative financial information has been recast from U.S. dollars to Canadian dollars to reflect the Company's consolidated financial statements as if they had been historically reported in Canadian dollars, consistent with ASC 830, *Foreign Currency Matters*.

The consolidated United States dollar balance sheet at December 31, 2010 was translated into the Canadian dollar reporting currency by translating assets and liabilities at the end-of-period exchange rate and translating equity balances at historical exchange rates. The consolidated statement of operations was translated into Canadian dollars using the weighted average exchange rate for the period. The resulting foreign currency translation adjustment is reported as a component of other comprehensive income and accumulated other comprehensive income.

Consistent with all of the other financial information in the consolidated financial statements, the quarterly information has also been recast from U.S. dollars to Canadian dollars. See note 23 for selected quarterly information.

Functional Currency

The Company changed the functional currency of Lone Pine prospectively from October 1, 2011 from the U.S. dollar to the Canadian dollar. The change in functional currency did not have a significant impact on the Company's consolidated financial statements for either the fourth quarter of 2011 or the year ended December 31, 2011 as Lone Pine's operations are primarily carried out by its operating subsidiary, LPR Canada. The functional currency of LPR Canada has not changed and continues to be the Canadian dollar.

As a result of this change in functional currency, there is no difference between the reporting currency and the functional currency of the Company and any of its subsidiaries.

(3) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Consolidation

These consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. All intercompany accounts and transactions have been eliminated.

Assumptions, Judgments and Estimates

In the course of preparing the consolidated financial statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions,

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

judgments and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could materially differ from amounts previously established. In the opinion of management, all adjustments have been made that are necessary for a fair presentation of the financial position of Lone Pine and the results of its operations, its cash flows and changes in its stockholders' equity for the periods presented.

The more significant areas requiring the use of assumptions, judgments and estimates relate to volumes of proved oil and natural gas reserves used in calculating depletion, the amount of future net revenues used in computing the ceiling test limitation and the amount of future capital costs and abandonment obligations used in such calculations, determining impairments of investments in unproved properties, valuing deferred tax assets and goodwill and estimating fair values of financial instruments, including derivative instruments.

Property and Equipment

The Company uses the full cost method of accounting for oil and natural gas properties. All of the Company's oil and natural gas operations are conducted in Canada. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, dry holes and overhead directly related to exploration and development activities) and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities are capitalized. Interest costs related to significant unproved properties that are under development are also capitalized to oil and natural gas properties.

Investments in unproved properties, including capitalized interest costs, are not depleted pending determination of the existence of proved reserves. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, geographic and geologic data obtained relating to the properties and estimated discounted future net cash flows from the properties. Estimated discounted future net cash flows are based on discounted future net revenues associated with probable and possible reserves, risk adjusted as appropriate. Where it is not practicable to assess individually the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. If an impairment is identified, the amount of the impairment assessed is added to the costs to be amortized.

The Company performs a ceiling test each quarter. The full cost ceiling test is a limitation on capitalized costs prescribed by Securities and Exchange Commission ("SEC") Regulation S-X Rule 4-10. The ceiling test is not a fair value based measurement. Rather, it is a standardized mathematical calculation. The ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for a cost center may not exceed the sum of: (1) the present value of future net revenue from estimated production of proved oil and natural gas reserves using current prices (as discussed below), excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, at a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax basis of oil and natural gas properties. Should the net capitalized costs

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

for a cost center exceed the sum of the components noted above, a ceiling test write-down would be recognized to the extent of the excess capitalized costs.

The prices that are used in the ceiling test are based on average of the first day of the month prices during the 12-month period prior to the reporting date, pursuant to the SEC's "Modernization of Oil and Gas Reporting" rule, which was first effective for the ceiling test calculated as of December 31, 2009. For all ceiling test calculations before December 31, 2009, prices were based on spot prices at the respective date.

Gain or loss is not recognized on the sale of oil and natural gas properties unless the sale significantly alters the relationship between capitalized costs and estimated proved oil and natural gas reserves attributable to a cost center.

The Company computes depletion of oil and natural gas properties on a quarterly basis using the unit-of-production method based upon production and estimates of proved reserve quantities. Future development costs related to properties with proved reserves are also included in the amortization base for computation of depletion. The depletion rate is adjusted for quarterly purposes in the event of significant changes to the calculation, such as a significant increase or decrease in the volume of proved reserves.

Certain gas gathering assets are depreciated on the units-of-production method whereby the capitalized costs are amortized over the total estimated throughput of the system. Furniture and fixtures, computer hardware and software, other equipment and leasehold improvements are depreciated on the straight-line or declining balance method based upon their estimated useful lives. Depreciation related to assets under capital leases is recorded as part of depreciation, depletion and amortization in the consolidated statement of operations.

Revenue Recognition

The Company recognizes revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when: (1) persuasive evidence of an arrangement exists, (2) delivery has occurred, (3) the seller's price to the buyer is fixed or determinable and (4) collectability is reasonably assured. Revenue represents the Company's share and is recorded net of royalty payments.

Stock-based Compensation

The Company issues stock options and other share-based compensation to its directors, officers and employees.

For stock-based compensation related to Lone Pine's plans, total compensation cost is based on the grant date fair value for equity awards and is based on the estimated settlement value for liability awards. For both types of awards, these values are determined using the Company's share price. The Company recognizes stock-based compensation expense for all awards over the service period required to earn the award, which is the shorter of the vesting period or the time period an employee becomes eligible to retain the award at retirement. For awards that have graded vesting provisions, the Company amortizes these awards on a graded vesting basis. As stock-based compensation expense recognized in the consolidated statements of operations is based on awards ultimately expected to vest, it has been

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

reduced for estimated forfeitures. Forfeitures are estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For stock-based compensation related to Forest's plans, costs were recorded to the payable to Forest as each was satisfied by Forest with Forest common stock. Phantom stock unit compensation cost was recorded to a separate liability since the units were settled in cash or shares. When phantom stock units were settled in stock, the liability was transferred to the payable to Forest since the units were settled by Forest with Forest common stock.

Foreign Currency Translation

Gains or losses from remeasuring the financial statements of companies with a functional currency different than the reporting currency are included in other comprehensive income, while gains or losses from remeasuring foreign currency transactions into the functional currency are included in the consolidated statements of operations.

Income Taxes

The Company recognizes deferred tax liabilities and assets for the expected future tax consequences of temporary differences between financial accounting bases and tax bases of assets and liabilities. 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 and carryforwards are expected to be recovered or settled. Income tax amounts related to different tax jurisdictions are not offset. The tax benefits of tax loss carryforwards and other deferred tax benefits are recorded as an asset to the extent that management assesses the utilization of such assets to be more likely than not. When the future utilization of some portion of the deferred tax asset is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded deferred tax assets.

Debt

Incremental costs associated with our bank credit facility are capitalized in other assets and are amortized over the term of the specific facility.

Asset Retirement Obligations

Lone Pine's asset retirement obligations include costs related to the plugging of wells, the removal of facilities and equipment and site restoration on oil and natural gas properties. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. The liability is initially measured at fair value using the credit adjusted interest rate to discount the obligation and capitalized to capital assets as an asset retirement cost. Subsequent to initial measurement, the asset retirement obligation is accreted each period to its present value. Accretion is recognized within the "other, net" line item on the consolidated statements of operations. The asset retirement costs that are capitalized are depleted as a component of the full cost pool using the units-of-production method and recognized as part of depletion, depreciation and amortization on the consolidated statements of operations. If estimated future costs of asset retirement obligations change, an adjustment is recorded to both the asset retirement obligation and oil and gas properties. Revisions to the estimated asset retirement obligation can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Employee Benefits

The Company recognizes an expense for its defined contribution pension plan as the benefits are earned by employees.

The Company accounts for its postretirement benefits plan by recognizing the underfunded status of the plan as an asset or liability in its consolidated balance sheet and recognizing changes in that funded status in the year in which the changes occur through other comprehensive income.

Allowance for Doubtful Accounts

The Company estimates losses on receivables based on known uncollectible accounts, if any, and historical experience of losses incurred.

Inventory

Inventory, which is primarily comprised of materials and supplies that have been acquired for use in future drilling operations, is carried at the lower of cost or market value.

Goodwill

Goodwill is not subject to amortization, and therefore the Company is required to make an annual impairment assessment, which is performed in the fourth quarter of each year. In addition, the Company tests goodwill for impairment if events or circumstances change between annual tests indicating a possible impairment. The impairment assessment requires the Company to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. Although the Company bases its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or depressed oil and natural gas prices could lead to an impairment of goodwill in future periods.

Derivative Instruments

The Company records all derivative instruments as either assets or liabilities at fair value, other than the derivative instruments that meet the normal purchases and sales exception. The Company has not elected to designate its derivative instruments as hedges and, therefore, records all changes in fair value of its derivative instruments through earnings, with such changes reported in a single line item on the consolidated statements of operations together with realized gains and losses on the derivative instruments. In the consolidated statements of cash flows, realized gains and losses are recorded within net cash provided by operating activities.

Cash Equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Earnings (loss) per Share

Basic earnings (loss) per share is computed using the two-class method by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. The two-class method of computing earnings per share is required for those entities that have participating securities or multiple classes of common stock. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. Holders of restricted stock issued under Lone Pine's stock incentive plan have the right to receive non-forfeitable cash dividends, participating on an equal basis with common stock. Holders of phantom stock units issued to directors under Lone Pine's stock incentive plan also have the right to receive non-forfeitable cash dividends, participating on an equal basis with common stock, while phantom stock units issued to employees do not participate in dividends. In summary, Lone Pine restricted stock awards and director phantom stock units are participating securities, and earnings are allocated to both common stock and these participating securities under the two-class method. However, these participating securities do not have a contractual obligation to share in Lone Pine's losses. Therefore, in periods of net loss, none of the loss is allocated to these participating securities.

Diluted earnings per share is the more dilutive calculation using either the two-class method (as addressed above) or the treasury stock method. Under the treasury stock method, diluted earnings (loss) per share is computed by dividing (a) net earnings (loss), adjusted for the effects of certain contracts, if any, that provide the issuer or holder with a choice between settlement methods, by (b) the weighted average number of common shares outstanding, adjusted for the dilutive effect, if any, of potential common shares.

Recent Accounting Pronouncements

In June 2011, the FASB issued Accounting Standards Update No. 2011-04, *Fair Value Measurement, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* ("ASU 2011-04"), which amends the current GAAP fair value measurement and disclosure guidance, to converge GAAP and IFRS requirements for measuring amounts at fair value as well as disclosures about these measurements. Many of the amendments clarify existing concepts and are not expected to result in significant changes to how companies apply the fair value principles. This authoritative guidance is effective for interim and annual periods beginning after December 15, 2011. Lone Pine is currently evaluating the impact that the adoption of this authoritative guidance will have on its consolidated financial statements.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, *Intangibles—Goodwill and Other (Topic 350), Testing Goodwill for Impairment*, which permits entities to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount to determine whether it is necessary to perform the two-step goodwill impairment test. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. However, if an entity concludes otherwise, it is required to perform the first step of the two-step impairment test, which may then lead an entity to performing the second step as well. Entities have the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to the first step of the two-step impairment test.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

This authoritative guidance is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of this authoritative accounting guidance may change the methodology that the Company uses to test its goodwill for impairment depending on the events or circumstances at the time the test is performed.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, *Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities* (“ASU 2011-11”), which requires that an entity disclose both gross and net information about instruments and transactions that are either eligible for offset in the balance sheet or subject to an agreement similar to a master netting agreement, including derivative instruments. ASU 2011-11 was issued in order to facilitate comparisons between GAAP and IFRS financial statements by requiring enhanced disclosures, but does not change existing GAAP that permits balance sheet offsetting. This authoritative guidance is effective for annual reporting periods beginning on or after January 1, 2013 and interim periods within those annual periods. Lone Pine is currently evaluating the impact that the adoption of this authoritative guidance will have on its consolidated financial statements.

In December 2011, the FASB issued Accounting Standards Update No. 2011-12, *Comprehensive Income, Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income* in Accounting Standards Update No. 2011-05 (“ASU 2011-12”), which indefinitely defers the requirements in adopted Accounting Standards Update No. 2011-05, *Comprehensive Income, Presentation of Comprehensive income* (“ASU 2011-05”) to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income (see note 4 for additional information). The adoption of this authoritative guidance will not have an impact on the Company’s consolidated financial statements until the specific changes that were proposed under ASU 2011-05 are finalized and issued by the FASB.

(4) ADOPTION OF NEW ACCOUNTING STANDARDS

In the fourth quarter of 2011, Lone Pine early adopted ASU 2011-05, except for the specific changes that have been deferred under ASU 2011-12, as noted above. The adoption of ASU 2011-05 required the Company to present items of net income, items of other comprehensive income and total comprehensive income either in a single continuous statement or in two separate consecutive statements and eliminated the option to report other comprehensive income and its components in the statement of stockholders’ equity. Lone Pine has elected to present two separate consecutive statements. Other than a change in presentation, the adoption of ASU 2011-05 did not have any impact on the Company’s consolidated financial statements.

In 2011, the Company adopted ASU 2010-29, “Business Combinations (Topic 805)—Disclosure of Supplementary Pro Forma Information for Business Combinations,” which updated the current authoritative guidance pertaining to the disclosure requirements for a business combination. Other than requiring additional pro forma revenue and earnings disclosure related to a business combination, the adoption of ASU 2010-29 did not have any impact on the Company’s consolidated financial statements.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(5) ACCOUNTS RECEIVABLE

The components of accounts receivable include the following:

	December 31,	
	2011	2010
	(In thousands)	
Oil and natural gas sales	\$19,210	\$13,098
Joint interest billings	5,506	11,961
Due from the Government of the Province of Alberta	—	4,563
Other	4,533	3,833
Allowance for doubtful accounts	(445)	(229)
Total accounts receivable	<u>\$28,804</u>	<u>\$33,226</u>

At December 31, 2011, three customers accounted for more than 10 percent of total accounts receivable, which accounted for \$12.3 million of accounts receivable.

Lone Pine's accounts receivable are primarily from purchasers of the Company's oil, natural gas and natural gas liquids and from other exploration and production companies which own working interests in the properties that the Company operates. This industry concentration could adversely impact Lone Pine's exposure to credit risk because the Company's customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices and other conditions. Lone Pine's production is sold to various purchasers in accordance with the Company's credit policies and procedures. These policies and procedures take into account, among other things, the creditworthiness of potential purchasers and concentrations of credit risk. Lone Pine generally requires letters of credit or parental guarantees for receivables from parties that are deemed to have sub-standard credit or other financial concerns, unless the Company can otherwise mitigate the perceived credit exposure. Lone Pine believes that the loss of one or more of the Company's current purchasers would not have a material adverse effect on the Company's ability to sell its production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption.

(6) INVENTORY

Inventory, which is classified as Other non-current assets on the consolidated balance sheet, was comprised of \$6.1 million of materials and supplies as of December 31, 2011 as compared to \$9.9 million as of December 31, 2010. In the fourth quarter of 2011, Lone Pine recognized a reduction in the carrying value of certain inventory by \$2.3 million (\$1.7 million after-tax), which was recorded within "Other, net" on the Statement of Operations. The reduction was based on estimated selling prices and primarily related to material and supplies that had been purchased for natural gas development projects. We were not required to take an impairment charge on the carrying value of our inventory during the years ended December 31, 2010 and 2009.

(7) PROPERTY AND EQUIPMENT

Business Combination

On April 29, 2011, the Company completed the acquisition of certain natural gas properties located in the Narraway/Ojay area. The acquisition increased the Company's working interests in

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(7) PROPERTY AND EQUIPMENT (Continued)

certain properties already owned and operated by the Company in the area and provided additional capacity in gathering systems and a gas plant in the area. The acquisition was accounted for using the acquisition method of accounting, which requires the assets and liabilities acquired to be recorded at their fair values at the date of acquisition. The following table reconciles the provisional estimates of fair values to the final estimates of fair value, which were based on additional analysis of the properties acquired:

	<u>Provisional</u>	<u>Change</u>	<u>Final</u>
	(In thousands)		
Proved properties	\$52,060	(11,606)	\$40,454
Unproved properties	14,685	11,600	26,285
Gas plant/pipelines	8,000	—	8,000
Asset retirement obligations	(98)	(194)	(292)
	<u>\$74,647</u>	<u>(200)</u>	<u>\$74,447</u>

As a result of the final estimates of fair value, depreciation, depletion and amortization for the second and third quarters of 2011 was reduced by \$0.4 million in total, which increased net earnings by \$0.3 million. The increase to earnings per share was less than \$0.01.

The consolidated statement of operations for the year ended December 31, 2011 included \$7.9 million of revenue from these properties since their acquisition date of April 29, 2011 and reduced net earnings by approximately \$0.8 million. The disclosure of supplemental pro forma information, which would disclose Lone Pine's consolidated revenue and net earnings as though the business combination had occurred at January 1, 2010, is not available because it has been impractical for the Company to obtain sufficient information regarding the revenues and costs related to the properties in previous periods. As a result, the required pro forma disclosures would require significant estimates which could not be objectively or independently verified.

Capitalization of Costs

Under the full cost method of accounting, Lone Pine capitalized the following amounts for the years indicated:

	<u>Year Ended December 31,</u>		
	<u>2011</u>	<u>2010</u>	<u>2009</u>
	(In thousands)		
General and administrative (including stock-based compensation)	\$4,486	\$5,773	\$6,108
Interest on unproved properties	675	791	—

Ceiling Test Write-down

The ceiling test calculation uses prices that are based on the average of the first day of the month prices during the 12-month period prior to the reporting date. Although the Company did not recognize a ceiling test write-down at December 31, 2011, the recent decline in the price of natural gas has increased the possibility of recognizing non-cash ceiling test write-downs in future periods.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(7) PROPERTY AND EQUIPMENT (Continued)

The March 31, 2009 ceiling test, which was based on March 31, 2009 spot prices, resulted in a non-cash write-down of oil and natural gas property costs of \$251.0 million. All ceiling tests performed, beginning with the December 31, 2009 ceiling test, have been based on the average of the first-day-of-the-month prices during the 12-month period prior to the reporting date.

Net Property and Equipment

Net property and equipment consists of the following as of the dates indicated:

	<u>December 31,</u>	
	<u>2011</u>	<u>2010</u>
	(In thousands)	
Oil and natural gas properties:		
Proved	\$ 1,907,987	\$ 1,595,666
Unproved	138,727	105,744
Accumulated depletion	(1,203,755)	(1,119,437)
Net oil and natural gas properties	842,959	581,973
Other property and equipment		
Gas gathering, furniture and fixtures, computer hardware and software and other equipment	75,060	67,982
Accumulated depreciation and amortization	(8,647)	(8,016)
Net other property and equipment	66,413	59,966
Total net property and equipment	<u>\$ 909,372</u>	<u>\$ 641,939</u>

The following table sets forth a summary of Lone Pine's investment in unproved properties as of December 31, 2011, by the year in which such costs were incurred:

	<u>Total</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008 and Prior</u>
	(In thousands)				
Acquisition costs	\$ 81,124	\$37,510	\$23,828	\$ 8,808	\$10,978
Exploration costs	56,137	16,707	6,476	3,084	29,870
Capitalized interest	1,466	675	791	—	—
Total	<u>\$138,727</u>	<u>\$54,892</u>	<u>\$31,095</u>	<u>\$11,892</u>	<u>\$40,848</u>

The majority of the unproved oil and natural gas property costs relate to oil and natural gas property acquisitions and leasehold acquisition costs as well as work-in-progress on various projects. As of December 31, 2011, the Company expects that substantially all of its unproved property costs will be reclassified to proved properties within ten years.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(8) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the activity for the Company's asset retirement obligations for the years indicated:

	Year Ended December 31,	
	2011	2010
	(In thousands)	
Asset retirement obligations at beginning of year	\$14,105	\$15,571
Accretion expense	1,071	1,073
Liabilities incurred	155	448
Liabilities assumed on acquisition	292	—
Liabilities settled	(148)	(295)
Divestiture of properties	—	(1,046)
Revisions of estimated liabilities	540	(1,646)
Asset retirement obligations at end of year	16,015	14,105
Less: current asset retirement obligations	603	438
Long-term asset retirement obligations	<u>\$15,412</u>	<u>\$13,667</u>

(9) DEBT

The components of debt are as follows:

	December 31,	
	2011	2010
	(In thousands)	
Bank credit facility	\$331,000	\$ —
Note payable to Forest Oil Corporation	—	248,839
	<u>\$331,000</u>	<u>\$248,839</u>

Bank Credit Facility

On March 18, 2011, Lone Pine entered into a \$500 million credit facility among Lone Pine, as parent, LPR Canada, as borrower, and a syndicate of banks led by JPMorgan Chase Bank, N.A., Toronto Branch (the "Credit Facility"). The Credit Facility became effective upon the closing of the IPO, and replaced the existing LPR Canada bank credit facility at such time. The Credit Facility will mature on March 18, 2016. Availability under the Credit Facility is governed by a borrowing base, which was \$425 million at December 31, 2011, and was reduced to \$375 million as a result of issue of Senior Notes in February 2012 (see note 24 for additional information on the Senior Notes). The determination of the borrowing base is made by the lenders, in their sole discretion, taking into consideration the estimated value of LPR Canada's oil and natural gas properties in accordance with the lenders' customary practices for oil and gas loans. The borrowing base will be redetermined semi-annually, and the available borrowing amount under the Credit Facility could increase or decrease based on such redetermination. The next scheduled redetermination of the borrowing base is expected to occur on or about May 1, 2012. In addition to the scheduled semi-annual redeterminations, LPR

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(9) DEBT (Continued)

Canada and the lenders each have discretion at any time, but not more often than once during any calendar year, to have the borrowing base redetermined.

The borrowing base is also subject to change in the event (1) Lone Pine or any of its subsidiaries issue senior unsecured notes, in which case the borrowing base will immediately be reduced by an amount equal to 25% of the stated principal amount of such issued senior unsecured notes, excluding any senior unsecured notes that Lone Pine or any of its subsidiaries may issue to refinance then-existing senior notes, or (2) LPR Canada sells oil and natural gas properties included in the borrowing base having a fair market value in excess of 10% of the borrowing base then in effect. The borrowing base is subject to other automatic adjustments under the Credit Facility. A lowering of the borrowing base could require LPR Canada and Lone Pine to repay indebtedness in excess of the borrowing base in order to cover a deficiency.

Borrowings under the Credit Facility bear interest at one of two rates that may be elected by LPR Canada. Borrowings bear interest at a rate based on either:

- (1) the sum of the applicable bankers' acceptance rate (as determined in accordance with the terms of the Credit Facility), and a stamping fee of between 175 to 275 basis points, depending on borrowing base utilization; or
- (2) the Canadian Prime Rate (as determined in accordance with the terms of the Credit Facility) plus 75 to 175 basis points, depending on borrowing base utilization.

The Credit Facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends and mergers and acquisitions, and also includes a financial covenant. The Credit Facility provides that LPR Canada will not permit its ratio of total debt outstanding to consolidated EBITDA (as adjusted for non-cash charges) for a trailing 12-month period to be greater than 4.00 to 1.00.

Under certain conditions, amounts outstanding under the Credit Facility may be accelerated. Bankruptcy and insolvency events with respect to Lone Pine, LPR Canada, or certain of Lone Pine's or LPR Canada's subsidiaries will result in an automatic acceleration of the indebtedness under the Credit Facility. Subject to notice and cure periods, certain events of default under the Credit Facility will result in acceleration of the indebtedness under the facility at the option of the lenders. Such other events of default include non-payment, breach of warranty, non-performance of obligations under the Credit Facility (including the financial covenant), default on other indebtedness, certain pension plan events, certain adverse judgments, change of control and a failure of the liens securing the Credit Facility.

The Credit Facility is collateralized by LPR Canada's assets. Under the Credit Facility, LPR Canada is required to mortgage and grant a security interest in 75% of the present value of the proved oil and natural gas properties and related assets of LPR Canada and its subsidiaries. LPR Canada is required to pledge, and has pledged, the stock of its subsidiary to the lenders to secure the Credit Facility. Under certain circumstances, LPR Canada could be obligated to pledge additional assets as collateral. The stock of all of Lone Pine's subsidiaries has been pledged to the lenders to secure the Credit Facility. Lone Pine and certain of its other subsidiaries have guaranteed the obligations of LPR Canada under the Credit Facility.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(9) DEBT (Continued)

Of the \$500 million total nominal amount under the Credit Facility, JPMorgan Chase Bank and 10 other banks hold 100% of the total commitments, with JPMorgan Chase holding 13.3% of the total commitments, two lenders holding 11.7% each of the total commitments, three lenders holding 10% each of the total commitments, and the other lenders holding 6.7% each of the total commitments.

From time to time, Lone Pine and its affiliates have engaged or may engage in other transactions with a number of the lenders under the Credit Facility. Such lenders or their affiliates have served as underwriters or initial purchasers of Lone Pine's equity securities, serve as counterparties to LPR Canada's commodity derivative agreements, and may, in the future, act as agent or directly purchase LPR Canada's production.

As of December 31, 2011, the weighted average interest rate on amounts borrowed under the Credit Facility was 3.7603%, and the commitment fee on the unused portion of the borrowing base was 0.5%.

Note Payable to Forest

The terms of the note payable to Forest called for principal amounts to be repaid upon Forest's demand or, failing such demand, on November 11, 2014. However, in June 2011, proceeds from the IPO and borrowings under the Credit Facility were used to repay the note, and the note was cancelled. The interest rate charged on borrowings under the note during the periods presented was set at three-month LIBOR plus two times Forest's credit default swap rate, with such interest rate being reset on the first day of each quarter. As of December 31, 2010, the note payable was US\$250.2 million and the interest rate on amounts borrowed under the Note Payable was 2.663%.

Interest

The following table summarizes interest costs incurred and the amount capitalized during the years indicated.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Interest costs	\$10,709	\$7,981	\$18,466
Less: interest costs capitalized	(675)	(791)	—
Interest expense	<u>\$10,034</u>	<u>\$7,190</u>	<u>\$18,466</u>

(10) CAPITAL LEASES

In April 2011, Lone Pine entered into a sale-leaseback transaction where Lone Pine sold compressors and surface equipment for \$7.7 million and simultaneously entered into a capital lease that provides for annual lease payments of approximately \$1.5 million for five years. Lone Pine did not have any capital lease agreements as of December 31, 2010.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) CAPITAL LEASES (Continued)

The Company's assets recorded under capital leases are set forth in the table below.

	<u>December 31, 2011</u>
	<u>(In thousands)</u>
Property and equipment	\$ 6,356
Other assets	1,367
Less accumulated amortization and impairment	<u>(1,221)</u>
	<u>\$ 6,502</u>

The Company's future minimum lease payments under capital leases, together with the present value of the net minimum lease payments, are set forth in the table below.

	<u>December 31, 2011</u>
	<u>(In thousands)</u>
2012	\$ 1,476
2013	1,476
2014	1,476
2015	1,476
2016	<u>1,914</u>
Total minimum lease payments	\$ 7,818
Less amount representing interest	<u>(924)</u>
Present value of minimum lease payments	\$ 6,894
Less: current capital lease obligation	<u>(1,156)</u>
	<u>\$ 5,738</u>

(11) EMPLOYEE BENEFITS

Defined Contribution Pension Plan

Lone Pine sponsored a defined contribution pension plan under which the Company contributed matching contributions equal to \$0.4 million, \$0.4 million and \$0.3 million in the years ending December 31, 2011, 2010 and 2009, respectively.

Postretirement Benefits

Lone Pine provides postretirement benefits to former employees of LPR Canada, their beneficiaries and covered dependents. These benefits, which consist primarily of medical benefits payable on behalf of retirees, are closed to new participants.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(11) EMPLOYEE BENEFITS (Continued)

Expected Benefit Payments

As of December 31, 2011, it is anticipated that the Company will be required to fund the following estimated benefit payments for the postretirement benefits plan in the following years:

	Year Ended December 31,					
	2012	2013	2014	2015	2016	2017 - 2021
	(In thousands)					
Expected funding of postretirement benefits	\$61	\$61	\$62	\$64	\$68	\$386

Benefit Obligations

The following table sets forth the estimated benefit obligations associated with the Company's postretirement benefits plan.

	Year Ended December 31,	
	2011	2010
	(In thousands)	
Benefit obligation at the beginning of the year	\$1,071	\$1,154
Interest cost	42	51
Actuarial loss (gain)	203	(89)
Benefits paid	(43)	(45)
Benefit obligation at the end of the year	<u>\$1,273</u>	<u>\$1,071</u>

Fair Value of Plan Assets

There are no assets set aside under the postretirement benefit plan. Any benefit plan payments made by the Company are treated as contributions. The following table sets forth a rollforward of the fair value of the plan assets.

	Year Ended December 31,	
	2011	2010
	(In thousands)	
Fair value of plan assets at beginning of the year	\$ —	\$ —
Employer contribution	43	45
Benefits paid	(43)	(45)
Fair value of plan assets at the end of the year	<u>\$ —</u>	<u>\$ —</u>

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(11) EMPLOYEE BENEFITS (Continued)

Funded Status

The following table sets forth the funded status of the Company's postretirement benefits plan.

	Year Ended December 31,	
	2011	2010
	(In thousands)	
Excess of benefit obligation over plan assets	\$(1,273)	\$(1,071)
Net actuarial loss (recognized in accumulated other comprehensive income)	396	206
Net amount recognized	<u>\$ 877</u>	<u>\$ 865</u>

Annual Periodic Expense and Actuarial Assumptions

The following tables set forth the components of the net periodic cost and the underlying weighted average actuarial assumptions.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Interest cost	\$ 42	\$ 51	\$ 82
Recognized actuarial loss	13	19	28
Total net periodic expense	<u>\$ 55</u>	<u>\$ 70</u>	<u>\$ 110</u>
Assumptions used to determine net periodic expense:			
Discount rate	4.00%	4.50%	6.74%
Assumptions used to determine benefit obligations:			
Discount rate	4.35%	4.00%	4.50%

In 2010 and 2009, the discount rates were determined by adjusting the Moody's Aa Corporate bond yield to reflect the difference between the duration of the future estimated cash flows of the postretirement benefit obligations and the duration of the Moody's Aa index. In 2011, the Company refined its methodology used to determine the discount rate and used the rates produced by Natcan Investment Management ("Natcan") for December 31, 2011, which are also based on AA-rated corporate bonds. Natcan was retained by the Canadian Institute of Actuaries to produce the rates for the intended purpose of determining an appropriate rate for companies to value pension and other post-retirement benefit plan liabilities.

The Company estimates that net periodic expense for the year ended December 31, 2012, will include expense of \$26,200 resulting from the amortization of its related accumulated actuarial loss included in accumulated other comprehensive income at December 31, 2011.

The assumed health care cost trend rates that were used to measure the expected cost of benefits covered by the postretirement benefits plan were 9.0% in 2012, 8.5% in 2013, 8.0% in 2014, 7.5% in 2015 and 7.0% thereafter for the medical benefits and 6.2% in 2012, 5.9% in 2013, 5.6% in 2014, 5.3% in 2015 and 5.0% thereafter for the dental benefits.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(11) EMPLOYEE BENEFITS (Continued)

Assumed health care cost trend rates have a significant effect on the amounts reported for postretirement benefits. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2011:

	<u>1%</u> <u>Increase</u>	<u>1%</u> <u>Decrease</u>
	(In thousands)	
Effect on service and interest cost components	\$ —	\$ —
Effect on postretirement benefit obligation	\$190	\$(153)

(12) DERIVATIVE INSTRUMENTS

Commodity Derivatives

During the year ended December 31, 2011, Lone Pine entered into commodity swap derivative instruments to manage its exposure to commodity price risk caused by fluctuations in commodity prices, which protects and provides certainty on a portion of the Company's cash flows. Lone Pine's commodity derivative instruments generally serve as effective economic hedges of commodity price exposure; however, Lone Pine has elected not to designate its derivatives as hedging instruments for accounting purposes. As such, Lone Pine recognizes all changes in fair value of its derivative instruments as unrealized gains or losses on derivative instruments in the consolidated statements of operations.

The table below sets forth Lone Pine's outstanding commodity swaps as of December 31, 2011.

Swap Term	Commodity Swaps			
	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	MMBtu/d	Weighted Average Hedged Price per MMBtu	bbl/d	Weighted Average Hedged Price per bbl
Calendar 2012	25,000	US\$5.09	2,000	US\$102.35
Calendar 2012	—	—	1,000	\$100.98

The following table summarizes additional commodity swaps that were entered into between the period January 1, 2012 to March 20, 2012:

Swap Term	Commodity Swaps			
	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	MMBtu/d	Weighted Average Hedged Price per MMBtu	bbl/d	Weighted Average Hedged Price per bbl
Calendar 2013	—	—	500	\$102.00
Calendar 2013	—	—	500	US\$101.00

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(12) DERIVATIVE INSTRUMENTS (Continued)

Fair Value Amounts

The table below summarizes the location and fair value amounts of Lone Pine's derivative instruments reported in the consolidated balance sheets as of the dates indicated. For financial reporting purposes, Lone Pine does not offset asset and liability fair value amounts recognized for derivative instruments with the same counterparty under its master netting arrangements. See note 13 for additional information on the fair value of Lone Pine's derivative instruments.

	<u>December 31,</u>	
	<u>2011</u>	<u>2010</u>
	<u>(In thousands)</u>	
Assets:		
Current assets: derivative instruments	\$19,786	\$—
Derivative instruments	<u>—</u>	<u>—</u>
	<u>\$19,786</u>	<u>\$—</u>

The table below shows the amount of derivative instrument gains and losses reported in the consolidated statements of operations as "Losses (gains) on derivative instruments" for the years indicated. All of these gains relate to commodity derivatives, which are not designated as hedging instruments for accounting purposes.

	<u>Year Ended</u> <u>December 31,</u>		
	<u>2011</u>	<u>2010</u>	<u>2009</u>
	<u>(In thousands)</u>		
Realized gains on derivative instruments	\$ (8,381)	\$—	\$—
Unrealized gains on derivative instruments	<u>(19,786)</u>	<u>—</u>	<u>—</u>
Losses (gains) on derivative instruments	<u>\$(28,167)</u>	<u>\$—</u>	<u>\$—</u>

Due to the volatility of oil and natural gas prices, the estimated fair values of Lone Pine's commodity derivative instruments are subject to large fluctuations from period to period.

Credit Risk

Lone Pine executes with each of its derivative counterparties an International Swap and Derivatives Association, Inc. ("ISDA") Master Agreement, which is a standard industry form contract containing general terms and conditions applicable to many types of derivative transactions. Additionally, Lone Pine executes, with each of its derivative counterparties, a Schedule, which modifies the terms and conditions of the ISDA Master Agreement according to the parties' requirements and the specific types of derivatives to be traded. As of December 31, 2011, all of the derivative counterparties are lenders, or affiliates of lenders, under the Credit Facility, which provides that any security granted under the Credit Facility shall also extend to and be available to those lenders that are counterparties to derivative transactions with Lone Pine. None of these counterparties require collateral beyond that already pledged under the Credit Facility.

The ISDA Master Agreements and Schedules contain cross-default provisions whereby a default under the Credit Facility will also cause a default under the derivative agreements. Such events of

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(12) DERIVATIVE INSTRUMENTS (Continued)

default include non-payment, breach of warranty, non-performance of financial covenants, default on other indebtedness, certain pension plan events, certain adverse judgments, change of control and a failure of the liens securing the Credit Facility. In addition, bankruptcy and insolvency events with respect to Lone Pine or certain of its subsidiaries will result in an automatic acceleration of the indebtedness under the Credit Facility. None of these events of default are specifically credit-related, but some could arise if there were a general deterioration of Lone Pine's credit. The ISDA Master Agreements and Schedules contain a further credit-related termination event that would occur if Lone Pine were to merge with another entity and the creditworthiness of the resulting entity was materially weaker than that of Lone Pine.

Lone Pine's derivative counterparties are all financial institutions that are engaged in similar activities and have similar economic characteristics that, in general, could cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions. Lone Pine does not require the posting of collateral for its benefit under its derivative agreements. However, Lone Pine's ISDA Master Agreements and Schedules generally contain netting provisions whereby if on any date amounts would otherwise be payable by each party to the other, then on such date the party that owes the larger amount will pay the excess of that amount over the smaller amount owed by the other party, thus satisfying each party's obligations. These provisions generally apply to all derivative transactions, or all derivative transactions of the same type (e.g., commodity, interest rate, etc.), with the particular counterparty. If all counterparties failed, Lone Pine would be exposed to a risk of loss equal to this net amount owed to Lone Pine, the fair value of which was \$19.8 million at December 31, 2011. If Lone Pine suffered an event of default, each counterparty could demand immediate payment, subject to notification periods, of the net obligations due to it under the derivative agreements. At December 31, 2011, Lone Pine did not owe a net derivative liability to any counterparty. In the absence of netting provisions, at December 31, 2011, Lone Pine would be exposed to an aggregate risk of loss of \$19.8 million under its derivative agreements and Lone Pine's derivative counterparties would not be exposed to a risk of loss.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was enacted which, as part of a broader financial regulatory reform, includes derivatives reform that may impact Lone Pine's business. Congress delegated many of the details of the Dodd-Frank Act to federal regulatory agencies, which are in the process of writing and implementing new rules. Lone Pine is monitoring the impact, if any, that the Dodd-Frank Act and related rules will have on its existing derivative transactions under its outstanding ISDA Master Agreements and Schedules, as well as its ability to enter into such transactions and agreements in the future.

(13) FAIR VALUE MEASUREMENTS

The authoritative accounting guidance regarding fair value measurements for assets and liabilities measured at fair value establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers consist of: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Company's derivative assets include commodity derivatives. See note 12 for additional information on these instruments. The Company utilizes present value techniques to value its

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(13) FAIR VALUE MEASUREMENTS (Continued)

derivatives. Inputs to the valuations include published forward prices and credit risk considerations, including the incorporation of published interest rates and credit spreads. All of the significant inputs are observable; therefore, the Company's derivative instruments are included within the Level 2 fair value hierarchy.

The Company's assets measured at fair value on a recurring basis at December 31, 2011 are set forth in the table below. The Company has no liabilities measured at fair value on a recurring basis at December 31, 2011.

	Using Significant Other Observable Inputs (Level 2)
	(In thousands)
Assets:	
Commodity derivative instruments	\$19,786
Total	<u>\$19,786</u>

The fair values and carrying amounts of the Company's financial instruments are summarized below as of the dates indicated.

	December 31,			
	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Assets:				
Cash	\$ 276	\$ 276	\$ 573	\$ 573
Accounts receivable	28,804	28,804	33,226	33,226
Derivative instruments	19,786	19,786	—	—
Liabilities:				
Bank credit facility	331,000	331,000	—	—
Advances payable to Forest Oil Corporation	252	252	38,830	38,830
Accounts payable and accrued liabilities	75,450	75,450	41,976	41,976
Capital lease obligations	6,894	6,894	—	—
Note payable to Forest Oil Corporation	\$ —	\$ —	\$248,839	\$248,839

The Company used various assumptions and methods in estimating the fair values of its financial instruments. The carrying amount of the Credit Facility approximates fair value since borrowings under the Credit Facility bear interest at variable market rates. The carrying amounts of advances and note payable to Forest approximated fair value due to their short-term nature. The carrying amount of the capital lease obligation approximates fair value, as interest rates have not materially changed since the lease was executed. The methods used to determine the fair values of the derivative instruments are discussed above. The fair values of the other financial instruments, including cash, accounts receivable, accounts payable and accrued liabilities, approximate their carrying values due to their short-term nature.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(14) COMMITMENTS AND CONTINGENCIES

The table below shows the Company's future rental payments under non-cancelable operating leases and unconditional purchase obligations as of December 31, 2011.

	2012	2013	2014	2015	After 2015	Total
	(In thousands)					
Operating leases(1)	\$1,631	\$1,748	\$1,745	\$1,696	\$10,501	\$17,321
Firm transportation commitments	6,334	2,926	167	64	—	9,491
	<u>\$7,965</u>	<u>\$4,674</u>	<u>\$1,912</u>	<u>\$1,760</u>	<u>\$10,501</u>	<u>\$26,812</u>

(1) Includes future rental payments for office facilities and equipment and vehicles under the remaining terms of non-cancelable operating leases.

Rental payments under non-cancelable operating leases applicable to exploration and development activities and capitalized to oil and natural gas properties approximated \$0.4 million in each of the years ended December 31, 2011, 2010 and 2009. Rental payments under non-cancelable operating leases charged to expense approximated \$0.7 million, \$0.8 million and \$0.7 million in each of the years ended December 31, 2011, 2010 and 2009, respectively.

Payments under firm transportation commitments charged to expense were \$7.8 million, \$6.5 million and \$4.7 million for the years ended December 31, 2011, 2010 and 2009, respectively.

As of March 20, 2012, the Company had a delivery commitment of approximately 21,000 MMBtu/d of natural gas, which provides for a price equal to the greater of (1) the NYMEX Henry Hub price less US\$1.49 and (2) US\$1.00 per MMBtu to a buyer through October 31, 2014, unless the Henry Hub price exceeds US\$6.50 per MMBtu, at which point Lone Pine shares the amount of the excess equally with the buyer.

At December 31, 2011, there were outstanding letters of credit totaling \$1.6 million issued as security for performance under certain transportation agreements. There were no outstanding letters of credit as of December 31, 2010.

(15) REVENUES

The following table summarizes Lone Pine's customers who account for more than 10% of total revenues:

	Year Ended December 31,		
	2011	2010	2009
Number of significant customers	4	4	4
Relative percentage of total revenues for each customer	27, 23, 16, 10	27, 25, 14, 13	36, 13, 13, 12
Revenues from significant customers in total (\$ in millions)	\$ 145	\$ 119	\$ 94

Lone Pine believes that the loss of one or more of the Company's current customers would not have a material adverse effect on the Company's ability to sell its production, because any individual purchaser could be readily replaced by another customer, absent a broad market disruption.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(16) EARNINGS (LOSS) PER SHARE

Lone Pine issued 69,999,999 shares of common stock to Forest as partial consideration for Forest's contribution of its direct and indirect ownership interests in LPR Canada in connection with the IPO. This recapitalization, effected immediately prior to the IPO, is treated similar to a stock dividend in that the computations of basic and diluted earnings per share have been adjusted retroactively for all periods presented to reflect this change in capital structure. See notes 1 and 21 for more information on the IPO and the Distribution.

Consistent with all of the other financial information in the consolidated financial statements, earnings (loss) per share for the years ended December 31, 2010 and 2009 have been recast to reflect the change of reporting currency from the U.S. dollar to the Canadian dollar.

The following sets forth the calculation of basic and diluted earnings (loss) per share for the years presented.

	<u>Year Ended December 31,</u>		
	<u>2011</u>	<u>2010</u>	<u>2009</u>
	(In thousands)		
Net earnings (loss)	\$34,803	\$32,825	\$(177,746)
Net earnings attributable to participating securities	(12)	—	—
Net earnings (loss) attributable to common stock for basic and diluted earnings per share	<u>\$34,791</u>	<u>\$32,825</u>	<u>\$(177,746)</u>
Weighted average number of common shares outstanding during the year for basic earnings per share	78,795	70,000	70,000
Dilutive effects of potential common shares	—	—	—
Weighted average number of common shares outstanding during the year, including the effects of dilutive potential common shares, for diluted earnings per share	<u>78,795</u>	<u>70,000</u>	<u>70,000</u>
Basic earnings (loss) per common share	<u>\$ 0.44</u>	<u>\$ 0.47</u>	<u>\$ (2.54)</u>
Diluted earnings (loss) per common share	<u>\$ 0.44</u>	<u>\$ 0.47</u>	<u>\$ (2.54)</u>

At December 31, 2011, 69,903 shares were excluded from the diluted earnings per common share calculation as the effect was anti-dilutive. At December 31, 2010 and 2009, no shares were excluded from the diluted earnings per common share calculation.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(17) ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in accumulated other comprehensive income (loss) for the years presented are as follows:

	<u>Foreign Currency Translation</u>	<u>Minimum Postretirement Benefits Liability Adjustment</u>	<u>Income Taxes</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>
	(In thousands)			
Balance at December 31, 2008	\$ —	\$(522)	\$131	\$(391)
2009 activity	—	60	—	60
Income tax	<u>—</u>	<u>—</u>	<u>(15)</u>	<u>(15)</u>
Balance at December 31, 2009	—	(462)	116	(346)
2010 activity	44	256	—	300
Income tax	<u>—</u>	<u>—</u>	<u>(64)</u>	<u>(64)</u>
Balance at December 31, 2010	44	(206)	52	(110)
2011 activity	361	(190)	—	171
Income tax	<u>—</u>	<u>—</u>	<u>47</u>	<u>47</u>
Balance at December 31, 2011	<u>\$405</u>	<u>\$(396)</u>	<u>\$ 99</u>	<u>\$ 108</u>

The income tax amounts disclosed above only relate to the minimum postretirement benefits liability adjustment.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) STOCK-BASED COMPENSATION

The table below sets forth total stock-based compensation recorded during the years ended December 31, 2011, 2010 and 2009. Stock-based compensation costs for all three years include costs for Lone Pine employees participating in Forest's stock incentive plans. The year ended December 31, 2011 also includes costs associated with Lone Pine employees and directors participating in Lone Pine's own stock incentive plan. The table below also discloses the remaining unamortized amounts and weighted average amortization period as of December 31, 2011.

	<u>Restricted Stock</u>	<u>Performance Units</u>	<u>Stock Options</u>	<u>Phantom Stock Units</u>	<u>Total</u>
	(In thousands)				
Year ended December 31, 2011:					
Total stock-based compensation costs	\$113	\$ 309	\$ —	\$ 1,987	\$ 2,409
Less: stock-based compensation costs capitalized	<u>—</u>	<u>(131)</u>	<u>—</u>	<u>(829)</u>	<u>(960)</u>
Stock-based compensation costs expensed	<u>\$113</u>	<u>\$ 178</u>	<u>\$ —</u>	<u>\$ 1,158</u>	<u>\$ 1,449</u>
Year ended December 31, 2010:					
Total stock-based compensation costs	\$ —	\$ 98	\$ —	\$ 3,546	\$ 3,644
Less: stock-based compensation costs capitalized	<u>—</u>	<u>(42)</u>	<u>—</u>	<u>(2,036)</u>	<u>(2,078)</u>
Stock-based compensation costs expensed	<u>\$ —</u>	<u>\$ 56</u>	<u>\$ —</u>	<u>\$ 1,510</u>	<u>\$ 1,566</u>
Year ended December 31, 2009:					
Total stock-based compensation costs	\$ —	\$ —	\$ 24	\$ 1,432	\$ 1,456
Less: stock-based compensation costs capitalized	<u>—</u>	<u>—</u>	<u>(18)</u>	<u>(831)</u>	<u>(849)</u>
Stock-based compensation costs expensed	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 6</u>	<u>\$ 601</u>	<u>\$ 607</u>
At December 31, 2011:					
Unamortized stock-based compensation costs	<u>\$140</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 3,573</u>	<u>\$ 3,713</u>
Weighted average amortization period remaining years	<u>0.6</u>	<u>—</u>	<u>—</u>	<u>1.62</u>	<u>1.58</u>

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) STOCK-BASED COMPENSATION (Continued)

Stock Based Compensation—Lone Pine's Plan

The following table summarizes the activity in Lone Pine's plan for the year ended December 31, 2011. The restricted stock and phantom stock units granted to non-employee directors vests on the first anniversary of the date awarded, while the phantom stock units granted to officers and employees vest in equal tranches over a period of 3 years. There was no activity in Lone Pine's plan for the years ended December 31, 2010 or 2009.

	Restricted Stock			Phantom Stock Units		
	Number of Shares	Weighted Average Grant Date Fair Value of Lone Pine Common Shares	Vest Date Fair Value (In thousands)	Number of Units	Weighted Average Grant Date Fair Value of Lone Pine Common Shares	Vest Date Fair Value (In thousands)
Unvested at December 31, 2010 . . .	—					
Awarded	33,895	\$10.23		719,750	\$10.51	
Vested	—	—		—	—	
Forfeited	(7,693)	\$12.63	—	(18,800)	\$12.09	—
Unvested at December 31, 2011 . . .	<u>26,202</u>	<u>\$ 9.53</u>	<u>\$</u>	<u>700,950</u>	<u>\$10.47</u>	<u>\$</u>

Of the unvested phantom stock units at December 31, 2011:

- 43,701 units have been granted to Canadian resident directors and must be settled in shares of Lone Pine common stock. These units are accounted for as equity-settled units.
- 569,465 units have been granted to officers and employees and must be settled in cash. These units are accounted for as liability-settled units.
- 87,784 units have been granted to officers and employees and the Company may elect to settle these units in common stock or cash. These units are accounted for as liability-settled units.

For phantom stock units that are settled in shares in a future period Lone Pine expects to issue new shares of the Company.

The weighted average grant date fair value of the restricted stock and phantom stock units was determined by reference to the average of the high and low stock price of a share of Lone Pine common stock as published by the New York Stock Exchange on the date of grant, and translated to Canadian dollars at the foreign exchange rate at the grant date.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) STOCK-BASED COMPENSATION (Continued)

Stock-based Compensation—Forest's Performance and Phantom Stock Unit Plans

The following table summarizes the activity for Lone Pine employees in Forest's performance and phantom stock unit plans for the years ended December 31, 2011, 2010 and 2009.

	Performance Units			Phantom Stock Units		
	Number of Units	Weighted Average Grant Date Fair Value	Vest Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value	Vest Date Fair Value
	(In thousands, except number of units)					
Unvested at January 1, 2009				158,754	\$53.01	
Awarded	—	—		105,595	\$20.06	
Vested	—			(7,429)	\$48.19	\$ 108
Forfeited	—			(20,375)	\$50.02	
Unvested at December 31, 2009 . . .	—			236,545	\$38.71	
Awarded	12,500	\$31.87		153,085	\$27.07	
Vested	—			(64,250)	\$44.74	\$1,948
Forfeited	—			(42,550)	\$40.89	
Unvested at December 31, 2010 . . .	12,500			282,830	\$30.71	
Awarded	—	—		500	\$27.52	
Vested	—			(46,050)	\$62.42	\$1,220
Forfeited	—			(11,775)	\$23.26	
Unvested at September 30, 2011 . .	12,500			225,505	\$24.62	
Distribution adjustment factor(1) . .	1.52			1.52		
Adjusted Units	19,000	\$20.97		342,765	\$16.20	
Vested on Distribution	(19,000)	\$20.97	—	(342,765)	\$16.20	\$3,404
Balance at December 31, 2011	—			—		

- (1) Under the terms of the employee matters agreement entered into with Forest the adjustment to the number of outstanding units was determined based on a formula which referenced the Forest common stock price for a time period both prior to and subsequent to September 30, 2011.

The performance units were not paid because the performance criteria were not met.

In 2011, prior to the Distribution, the Company paid \$1.2 million (\$0.9 million after-tax) on the vesting of phantom stock units, of which all of the amounts were paid in cash with the exception of 300 units, which were settled in shares of Forest common stock. As a result of the Distribution, Lone Pine's employees were deemed to have been involuntarily terminated and therefore their phantom stock units vested in full. All of these units were subsequently settled in cash and the aggregate amount paid pursuant to the vesting of such awards was \$3.4 million (\$2.6 million after-tax), which was paid by Lone Pine under the terms of the employee matters agreement with Forest.

In 2010, 500 phantom stock units were settled in cash and 63,750 were settled in shares, and in 2009, all of the phantom stock units were settled in shares. The Company did not recognize a tax benefit on the settlement in 2010 or 2009 because the units were primarily settled in shares.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) STOCK-BASED COMPENSATION (Continued)

The weighted average grant date fair value of the phantom stock units was determined by reference to the average of the high and low stock price of a share of Forest common stock as published by the New York Stock Exchange on the date of grant, and translated to Canadian dollars at the foreign exchange rate at the grant date.

Stock-based Compensation—Forest's Stock Option Plan

The following table summarizes activity for Lone Pine employees in Forest's stock option plan for the years ended December 31, 2011, 2010 and 2009.

	Number of Options to Purchase Forest Common Shares	Weighted Average Exercise Price Forest Common Shares (US\$)	Aggregate Intrinsic Value (In thousands)	Number of Options Exercisable
Outstanding at January 1, 2009	168,944	\$20.78	\$ 22	164,674
Granted	—			
Exercised	—			
Cancelled	(60,026)	\$19.03		
Outstanding at December 31, 2009	108,918	\$21.75	\$338	108,918
Granted	—			
Exercised	(45,949)	\$20.52	\$388	
Cancelled	(10,000)	\$36.87		
Outstanding at December 31, 2010	52,969	\$19.97	\$957	52,969
Granted	—			
Exercised	(14,038)	\$18.35	\$ 81	
Cancelled	—			
Outstanding at September 30, 2011	38,931	\$20.55	\$ —	38,931
Distribution adjustment factor(1)	1.52			
Adjusted Units	59,175	\$13.52	\$ —	59,175
Exercised	(29,287)	\$12.18	\$108	
Cancelled	(29,888)	\$15.81		
Outstanding at December 31, 2011	—			—

(1) Under terms of the employee matters agreement entered into with Forest, the adjustment to the number of outstanding stock options was determined based on a formula which referenced the Forest common stock price for a time period both prior to and subsequent to September 30, 2011.

Stock options were granted at an exercise price equivalent to the fair market value of Forest common stock on the date of grant and had a term of ten years. Options granted to non-employee directors vested immediately and options granted to officers and other employees vested in increments of 25% on each of the first four anniversary dates of the date of grant.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(19) FOREIGN CURRENCY TRANSLATION

During the year ended December 31, 2011, Lone Pine realized a foreign currency exchange gain of \$32.7 million in connection with the repayment of debt owed to Forest. The gain was classified within financing activities in the consolidated statements of cash flows, and therefore the portion of the gain that related to the year ended December 31, 2011 (\$5.0 million) was reclassified from operating activities to financing activities. During the years ended December 31, 2010 and 2009, Lone Pine recorded \$13.7 million and \$18.8 million, respectively, of unrealized gains related to the note payable and advances due to Forest since each were denominated in U.S. dollars.

(20) INCOME TAXES

Income Tax Provision

The table below sets forth the provision for income taxes from continuing operations for the years presented.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Current:			
U.S. Federal and State	\$ —	\$ —	\$ —
Canadian Federal and Provincial	—	—	—
Deferred:			
U.S. Federal and State	—	—	—
Canadian Federal and Provincial	17,724	7,911	(63,066)
	<u>\$17,724</u>	<u>\$7,911</u>	<u>\$(63,066)</u>

Lone Pine is incorporated in Delaware, United States of America, and LPR Canada is incorporated in Alberta, Canada. All of the Company's activities are and have been conducted in Canada, and the Company expects that future cash flows generated by the Company will continue to be reinvested in Canada for exploration development or acquisition activities or utilized to satisfy other obligations in Canada. As such, no U.S. federal or state income taxes are included in the Company's provision for income taxes. Accordingly, the reconciliation presented in the table below of income taxes

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(20) INCOME TAXES (Continued)

calculated by applying statutory rates to our total income tax provision uses Canadian statutory rates rather than U.S. statutory rates.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Canadian federal income tax at 16.5%, 18.0% and 19.0% for 2011, 2010 and 2009, respectively, of income before income taxes	\$ 8,667	\$ 7,337	\$(45,754)
Canadian provincial income taxes at 10%, 10.0164% and 10.0130% for 2011, 2010 and 2009, respectively, of income before income taxes	5,253	4,082	(24,113)
Foreign currency translation gains and losses taxed at 50% of statutory rates	(551)	(1,682)	(2,307)
Change in the valuation allowance for deferred tax assets	4,857	(1,404)	(1,401)
Effect of future Canadian statutory rate reductions	(728)	(1,100)	9,696
Other	226	678	813
Total income tax	<u>\$17,724</u>	<u>\$ 7,911</u>	<u>\$(63,066)</u>

Net deferred tax assets and liabilities

The components of the net deferred tax assets and liabilities at December 31, 2011 and 2010 are as follows:

	December 31,	
	2011	2010
	(In thousands)	
Deferred tax assets:		
Accrual for postretirement benefits	\$ 318	\$ 268
Employee compensation accruals including stock-based compensation	679	1,343
Net operating loss carry forwards	855	470
Capital loss carry forwards	—	2,752
Capital lease	1,723	—
Asset retirement obligations	4,004	3,526
Other	42	664
Total gross deferred tax assets	7,621	9,023
Less valuation allowance	(950)	(470)
Net deferred tax assets	6,671	8,553
Deferred tax liabilities:		
Property and equipment	(76,644)	(61,926)
Unrealized gains on derivative contracts, net	(4,946)	—
Other	(8)	(3,878)
Total gross deferred tax liabilities	(81,598)	(65,804)
Net deferred tax liabilities	<u>\$(74,927)</u>	<u>\$(57,251)</u>

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(20) INCOME TAXES (Continued)

The net deferred tax assets and liabilities are reflected in the consolidated balance sheet as follows:

	December 31,	
	(In thousands)	
	2011	2010
Current deferred tax liabilities	\$ (4,946)	\$ —
Non-current deferred tax liabilities	(69,981)	(57,251)
	<u>\$(74,927)</u>	<u>\$(57,251)</u>

Valuation Allowance

The increase in the valuation allowance of \$4.9 million in 2011 is comprised of \$3.9 million related to resource successor tax pools and \$1.0 million related to U.S. Federal net operating losses. In 2010, the decrease in the valuation allowance of \$1.4 million relates primarily to the release of the valuation allowance placed on capital loss carry forwards in the amount of \$1.9 million offset by an amount of \$0.5 million placed on U.S. Federal net operating losses.

Canadian Income Tax matters

The limitation period is closed for the Company's Canadian income tax returns for years ended on or before December 31, 2006.

Allocation of Consolidated Income Tax

The income tax amounts calculated for LPR Canada were based on the specific transactions related to LPR Canada and Canadian income tax regulations. Until the date of the Distribution, Lone Pine's U.S. federal income tax items and attributes were included in Forest's consolidated U.S. income tax return, and in connection with the Distribution, Lone Pine was allocated a portion of the unused Forest consolidated loss carryforwards based on the specific amounts recognized by Lone Pine.

Accounting for Uncertainty in Income Taxes

The Company has determined that it is not necessary to recognize a provision for uncertain tax benefits as of December 31, 2011 and 2010 and, accordingly, no liability has been recorded.

(21) STOCKHOLDERS' EQUITY

At December 31, 2011, Lone Pine had authorized 300 million shares of common stock at a par value of \$0.01 per share and 15 million shares of preferred stock at a par value of \$0.01 per share. At December 31, 2011, Lone Pine had 85,026,202 common shares issued and outstanding and no preferred shares issued and outstanding. At December 31, 2010, Lone Pine had one common share issued and outstanding and no preferred shares issued and outstanding. At December 31, 2010, LPR Canada had 2,106 common shares and no preferred shares issued and outstanding.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(21) STOCKHOLDERS' EQUITY (Continued)

Equity Transactions with Forest

In May 2011, as part of a corporate restructuring in connection with the IPO and Distribution, LPR Canada declared a non-cash stock dividend to Forest in the amount of \$567.4 million. As consideration for Forest's contribution of its direct and indirect interests in LPR Canada to Lone Pine, Lone Pine issued 69,999,999 million shares of common stock and paid \$28.7 million in cash to Forest. Given that the transfer of the interests was a common control transaction, the cash distribution was recognized as a direct reduction of the capital surplus of Lone Pine. Forest also made an additional capital contribution of \$0.4 million in the third quarter of 2011.

Initial Public Offering

In December 2010, Forest announced its intention to separate its Canadian operations through an initial public offering of up to 19.9% of the common stock of its wholly-owned subsidiary, Lone Pine, which would hold Forest's ownership interests in its Canadian operations, followed by a distribution, or spin-off, of the remaining shares of Lone Pine held by Forest to its shareholders. On June 1, 2011, Lone Pine completed an initial public offering of 15 million shares of its common stock at a price of US\$13.00 per share (US\$12.22 per share, net of underwriting discounts and commissions). Upon completion of the IPO, Forest retained a controlling interest in Lone Pine, owning 82% of the outstanding shares of Lone Pine's common stock. The net proceeds from the IPO, after deducting underwriting discounts and commissions and offering expenses, received by Lone Pine were approximately \$173.1 million. Lone Pine used the net proceeds to pay \$28.7 million to Forest as partial consideration for Forest's contribution of Forest's direct and indirect interest in its Canadian operations. Lone Pine used the remaining net proceeds and borrowings under the Credit Facility to repay outstanding indebtedness owed to Forest.

Distribution

On September 30, 2011, Forest paid a special stock dividend to its shareholders of the 70 million shares of common stock of Lone Pine owned by Forest. The Distribution was made to all Forest shareholders of record as of the close of business on September 16, 2011, with Forest shareholders receiving 0.61248511 of a share of Lone Pine common stock for every share of Forest common stock held as of the record date. Forest shareholders received cash in lieu of fractional shares.

(22) RELATED PARTY TRANSACTIONS

Forest has historically provided to Lone Pine corporate services such as executive oversight, insurance and risk management, treasury, information technology, legal, accounting, tax, marketing, corporate engineering, human resources and other services for which Forest charged Lone Pine management and insurance fees. The management and insurance fees and other costs incurred by Forest on Lone Pine's behalf, such as direct costs associated with acquisition and divestiture activities, settlements of equity compensation awards to Lone Pine employees, and other general and administrative expenses, such as travel and legal, were accrued in a payable due to Forest, which was classified as a current liability within the consolidated balance sheet. Interest accrued on this balance, except for the portion attributable to equity compensation awards, at the prime interest rate plus 5% per annum. In addition to the payable due to Forest as discussed above, Lone Pine had a promissory note to Forest, under which Lone Pine could borrow up to \$500 million. This balance was paid off in

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(22) RELATED PARTY TRANSACTIONS (Continued)

June 2011 with the proceeds from the IPO and borrowings under the Credit Facility. On June 1, 2011, Forest and Lone Pine entered into a transition services agreement, pursuant to which Forest agreed to provide to Lone Pine, on a transitional basis, certain corporate services consistent with the services previously provided to Lone Pine. The charges for the transition services generally were intended to allow Forest to fully recover the costs directly associated with providing the services to Lone Pine, plus all out-of-pocket costs and expenses, without profit. The charges of each of the transition services generally were based on the product of (1) the number of hours each applicable Forest employee bills during the billing month and (2) such employee's total hourly compensation (based on his or her base salary plus applicable burden and bonus). The transition services agreement terminated on December 1, 2011. Lone Pine paid Forest \$0.3 million under the transition services agreement in 2011.

The amounts due to Forest as of the dates presented were as follows:

	December 31,	
	2011	2010
	(In thousands)	
Interest bearing advances	\$ (2)	\$ 13,831
Non-interest bearing advances	251	4,043
Accrued interest on interest bearing advances	3	836
Accrued interest on note payable	—	20,120
Advances and accrued interest payable to Forest Oil Corporation .	252	38,830
Note payable to Forest Oil Corporation	—	248,839
Total due to Forest Oil Corporation	<u>\$252</u>	<u>\$287,669</u>

The amounts of management and insurance fees and other reimbursable costs billed by Forest to Lone Pine and included in Lone Pine's consolidated financial statements for the periods presented are shown in the table below. This table does not include amounts due to Forest for stock-based compensation costs or interest charges.

	Year ended December 31,		
	2011	2010	2009
	(In thousands)		
Management and insurance fees	\$2,479	\$3,121	\$1,972
Other	100	1,574	901
	<u>\$2,579</u>	<u>\$4,695</u>	<u>\$2,873</u>

Immediately prior to the completion of the IPO, Lone Pine entered into a tax sharing agreement with Forest, which governs the respective rights, responsibilities and obligations of Lone Pine and Forest with respect to tax liabilities and benefits, tax attributes, the preparation and filing of tax returns, the control of audits and other tax proceedings and other matters regarding taxes.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(23) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

Consistent with all of the other financial information in the consolidated financial statements, the following information has been recast because of the change of reporting currency from the U.S. dollar to the Canadian dollar.

	<u>First Quarter</u>	<u>Second Quarter</u>	<u>Third Quarter</u>	<u>Fourth Quarter</u>
	(In thousands, except per share amounts)			
2011				
Oil and natural gas sales (US\$, as previously reported)	\$36,261	\$51,255	\$50,292	\$55,712
Oil and natural gas sales (recast in Canadian dollars)	35,562	49,236	50,015	56,357
Net earnings (loss) (US\$, as previously reported)*	\$ 5,488	\$ 5,748	\$28,036	\$(4,683)
Net earnings (loss) (recast in Canadian dollars)	5,291	5,366	29,014	(4,868)
Basic and diluted earnings (loss) per common share (US\$, as previously reported)	\$ 0.08	\$ 0.08	\$ 0.33	\$ (0.06)
Basic and diluted earnings (loss) per common share (recast in Canadian dollars)	\$ 0.08	\$ 0.07	\$ 0.34	\$ (0.06)
2010				
Oil and natural gas sales (US\$, as previously reported)	\$37,408	\$38,253	\$35,191	\$35,195
Oil and natural gas sales (recast in Canadian dollars)	39,067	39,827	36,654	35,636
Net earnings (loss) (US\$, as previously reported)	\$15,013	\$(2,877)	\$11,529	\$ 8,851
Net earnings (loss) (recast in Canadian dollars)	15,473	(3,159)	11,609	8,902
Basic and diluted earnings (loss) per common share (US\$, as previously reported)	\$ 0.21	\$ (0.04)	\$ 0.16	\$ 0.13
Basic and diluted earnings (loss) per common share (recast in Canadian dollars)	\$ 0.22	\$ (0.05)	\$ 0.17	\$ 0.13

* Net earnings for the second and third quarters of 2011 were increased by \$0.157 million and \$0.149 million, respectively, as a result of the final estimates of fair value in relation to the April 2011 business combination (see note 7 for more information).

(24) SUBSEQUENT EVENTS

On January 12, 2012, the Company granted 646,636 stock options and 869,384 phantom stock units to officers and employees of the Company. The stock options have an exercise price of US\$6.94, vest in three equal annual installments beginning on January 12, 2013 and have a five year term. The phantom stock units also vest in three equal annual installments beginning on January 12, 2013 and will be settled in newly-issued shares of common stock of the Company.

In February 2012, the Company's wholly-owned subsidiary, LPR Canada, issued US\$200 million of 10.375% Senior Notes due February 2017. The net proceeds of approximately \$192 million, after deduction of original issue and initial purchaser discounts and estimated offering expenses, were used to partially repay borrowings outstanding under the bank credit facility.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(25) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

Estimated Proved Oil and Gas Reserves

The reserve estimates as of December 31, 2011, 2010 and 2009 presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance issued by the FASB effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's "Modernization of Oil and Gas Reporting" rule, which was also effective for annual reports for fiscal years ending on or after December 31, 2009.

The above-mentioned rules include updated definitions of proved oil and gas reserves, proved undeveloped oil and gas reserves, oil and gas producing activities and other terms used in estimating proved oil and gas reserves. Proved oil and gas reserves as of December 31, 2011, 2010 and 2009 were calculated based on the prices for oil and gas during the 12-month period before the reporting date, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, rather than the year-end spot prices, which had been used in years prior to 2009. This average price is also used in calculating the aggregate amount of and changes in future cash inflows related to the standardized measure of discounted future cash flows. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. The authoritative guidance broadened the types of technologies that a company may use to establish reserve estimates and also broadened the definition of oil and gas producing activities to include the extraction of non-traditional resources, including bitumen extracted from oil sands as well as oil and gas extracted from shales. Data prior to December 31, 2009 presented throughout this footnote is not required to be, nor has it been, updated based on the new guidance.

Proved oil and gas reserves are those quantities of oil and gas, which, 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 prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Existing economic conditions include the average prices for oil and gas during the 12-month period before the reporting date for 2011, 2010 and 2009 and the year-end spot prices for oil and gas for 2008, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Prices do not include the effects of commodity derivatives. Existing economic conditions include year-end cost estimates for all years presented.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved undeveloped oil and gas reserves are 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.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(25) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES
(UNAUDITED): (Continued)

The following table sets forth the estimates of Lone Pine's net proved, net proved developed and net proved undeveloped oil and gas reserves, all of which are located in Canada, as of December 31, 2011, 2010, 2009 and 2008 and changes in its net proved oil and gas reserves for the years ended December 31, 2011, 2010 and 2009. For the year ended December 31, 2011, the Company engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to prepare an independent evaluation of the Company's reserves. For the years ended December 31, 2010, 2009 and 2008, the Company engaged DeGolyer and MacNaughton to conduct an audit of its internal reserve estimates.

	<u>Liquids</u> <u>(Mbbbls)</u>	<u>Gas</u> <u>(MMcf)</u>	<u>Total</u> <u>(MMcfe)</u>
Balance at December 31, 2008	8,836	237,515	290,531
Revisions of previous estimates	2,814	(33,020)	(16,136)
Extensions and discoveries	7,220	110,299	153,619
Production	(856)	(23,248)	(28,384)
Sales of reserves in place	<u>(1,160)</u>	<u>(70,345)</u>	<u>(77,305)</u>
Balance at December 31, 2009	16,854	221,201	322,325
Revisions of previous estimates	195	(7,724)	(6,554)
Extensions and discoveries	2,772	86,028	102,660
Production	(962)	(22,436)	(28,208)
Sales of reserves in place	<u>(602)</u>	<u>(10,183)</u>	<u>(13,795)</u>
Balance at December 31, 2010	18,257	266,886	376,428
Revisions of previous estimates	(2,404)	(51,496)	(65,919)
Extensions and discoveries	2,902	44,981	62,392
Production	(1,192)	(27,047)	(34,199)
Purchase of reserves in place	<u>—</u>	<u>62,145</u>	<u>62,145</u>
Balance at December 31, 2011	<u>17,563</u>	<u>295,469</u>	<u>400,847</u>
Proved developed reserves at:			
January 1, 2009	5,827	192,338	227,300
December 31, 2009	6,202	169,740	206,952
December 31, 2010	6,594	169,292	208,856
December 31, 2011	8,363	163,530	213,708
Proved undeveloped reserves at:			
January 1, 2009	3,009	45,177	63,231
December 31, 2009	10,652	51,461	115,373
December 31, 2010	11,663	97,594	167,572
December 31, 2011	9,200	131,939	187,139

Revisions of Previous Estimates

In 2011 and 2010, the net negative revisions were primarily due to the performance of existing wells.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

**(25) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES
(UNAUDITED): (Continued)**

In 2009, the net negative revisions were primarily related to a decrease in the natural gas price used to estimate reserve volumes.

Extensions and Discoveries

In 2011, the positive extensions and discoveries were primarily due to continued success with horizontal drilling in the Evi area and the ongoing development of the Narraway and Ojay fields.

In 2010, the positive extensions and discoveries were primarily due to successful drilling results in the Narraway and Ojay fields.

In 2009, the positive extensions and discoveries were primarily due to successful drilling results in the Narraway and Ojay fields and continued success with horizontal drilling in the Evi area.

Purchase of Reserves in Place

In 2011, the Company acquired proved reserves in our Narraway/Ojay fields as a result of the acquisition of certain natural gas properties.

Sales of Reserves in Place

In 2011, the Company did not divest any properties with associated reserves. In 2010 and 2009, the Company divested certain non-core oil and gas properties.

Aggregate Capitalized Costs

The aggregate capitalized costs relating to oil and gas producing activities were as follows as of the dates indicated:

		December 31,	
	2011	2010	2009
		(In thousands)	
Costs related to proved properties	\$ 1,907,987	\$ 1,595,666	\$ 1,461,110
Costs related to unproved properties	138,727	105,744	69,582
	2,046,714	1,701,410	1,530,692
Less accumulated depletion	(1,203,755)	(1,119,437)	(1,054,447)
	<u>\$ 842,959</u>	<u>\$ 581,973</u>	<u>\$ 476,245</u>

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(25) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES
(UNAUDITED): (Continued)

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

The following costs were incurred in oil and gas property acquisition, exploration and development activities during the years ended December 31, 2011, 2010 and 2009:

	December 31,		
	2011	2010	2009
	(In thousands)		
Property acquisition costs:			
Proved properties	\$ 48,362	\$ —	\$ —
Unproved properties	38,823	41,037	12,215
Exploration costs	24,809	8,791	29,529
Development costs	233,653	159,057	55,896
Total costs incurred(1)	<u>\$345,647</u>	<u>\$208,885</u>	<u>\$97,640</u>

(1) Includes amounts relating to changes in estimated asset retirement obligations of \$1.0 million, (\$1.1) million and \$1.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Results of Operations from Oil and Gas Producing Activities

Results of operations from oil and gas producing activities for the years ended December 31, 2011, 2010 and 2009 are presented below.

	December 31,		
	2011	2010	2009
	(In thousands)		
Oil and gas sales	\$191,170	\$151,184	\$ 127,396
Expenses:			
Production expense	58,378	40,164	43,617
Depletion expense	84,318	64,990	63,775
Ceiling test write-down of oil and gas properties	—	—	251,035
Accretion of asset retirement obligations	1,071	1,073	1,143
Income tax	12,562	12,588	(67,330)
Total expenses	<u>156,329</u>	<u>118,815</u>	<u>292,240</u>
Results of operations from oil and gas producing activities	<u>\$ 34,841</u>	<u>\$ 32,369</u>	<u>\$(164,844)</u>
Depletion rate per Mcfe	\$ 2.47	\$ 2.32	\$ 2.27

Standardized Measure of Discounted Future Net Cash Flows

Future oil and gas sales are calculated by applying the prices used in estimating the Company's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes were considered only to the extent provided by contractual arrangements in existence at each year-end.

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(25) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES
(UNAUDITED): (Continued)

Future production and development costs, which include costs related to plugging of wells, removal of facilities and equipment and site restoration, are calculated by estimating the expenditures to be incurred in producing and developing the proved oil and gas reserves at the end of each year, based on year-end costs and assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the estimated future pretax net cash flows relating to proved oil and gas reserves, less the tax bases of the properties involved. The future income tax expenses give effect to tax deductions, credits and allowances relating to the proved oil and gas reserves. All cash flow amounts, including income taxes, are discounted at 10%.

Changes in the demand for oil and natural gas, inflation and other factors make such estimates inherently imprecise and subject to substantial revision. The following table should not be construed to be an estimate of the current market value of the Company's proved reserves. Management does not rely upon the information that follows in making investment decisions.

	December 31,		
	2011	2010	2009
	(In thousands)		
Future oil and gas sales	\$2,741,149	\$2,347,271	\$2,058,113
Future production costs	(729,990)	(531,897)	(513,906)
Future development costs	(553,700)	(422,567)	(305,969)
Future income taxes	(231,174)	(302,916)	(263,694)
Future net cash flows	1,226,285	1,089,891	974,544
10% annual discount for estimated timing of cash flows	(607,352)	(561,398)	(449,953)
Standardized measure of discounted future net cash flows	<u>\$ 618,933</u>	<u>\$ 528,493</u>	<u>\$ 524,591</u>

LONE PINE RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(25) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES
(UNAUDITED): (Continued)

Changes in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

An analysis of the changes in the standardized measure of discounted future net cash flows during each of the last three years is as follows:

	December 31,		
	2011	2010	2009
	(In thousands)		
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	\$ 528,493	\$ 524,591	\$ 645,856
Changes resulting from:			
Sales of oil and gas, net of production costs . .	(149,122)	(110,422)	(84,428)
Net changes in prices and future production costs	63,069	56,497	(174,064)
Net changes in future development costs	(53,264)	(456)	29,142
Extensions, discoveries and improved recovery	82,914	109,906	240,074
Development costs incurred during the period	172,456	37,195	12,282
Revisions of previous quantity estimates	(143,718)	(14,527)	32,870
Changes in production rates, timing and other	(60,821)	(104,064)	(196,927)
Sales of reserves in place	—	(14,998)	(65,288)
Purchase of reserves in place	64,996	—	—
Accretion of discount on reserves at beginning of year	66,938	64,568	78,107
Net change in income taxes	46,992	(19,797)	6,967
Total change for year	<u>90,440</u>	<u>3,902</u>	<u>(121,265)</u>
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	<u>\$ 618,933</u>	<u>\$ 528,493</u>	<u>\$ 524,591</u>

Each year's computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves was based on 12-month average commodity prices, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month, prior to December 31 and year-end costs. The prices used in the computation were as follows:

	December 31,		
	2011	2010	2009
	(In thousands)		
Edmonton Light (\$ per barrel)	96.98	77.80	66.20
AECO (\$ per MMBtu)	3.77	4.07	3.95
WTI (US\$ per barrel)	96.13	79.81	61.08
Henry Hub (US\$ per MMBtu)	4.15	4.38	3.87

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) under 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 Form 10-K. 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 or submit 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 that evaluation our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2011 at the reasonable assurance level.

Report of Management on Internal Control over Financial Reporting

This Form 10-K does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the Company's registered public accounting firm, Ernst & Young LLP, regarding our internal control over financial reporting due to a transition period established by the rules of the SEC for newly public companies.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2011, there was no change in our system of internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act that has materially affected or is reasonably likely to materially affect our internal control over financial reporting.

Item 9B. Other Information

The following disclosure is included in this Form 10-K in lieu of filing a Current Report on Form 8-K to report events that have occurred within four business days prior to the filing of this Form 10-K.

First Amendment to Severance Agreements

In connection with our IPO, we entered into severance agreements with each of our executive officers, including David M. Anderson, our President and Chief Executive Officer, and certain of our key employees. On March 21, 2012, the Board approved the entry by Lone Pine into the first amendment to the severance agreements with each of Charles R. Kraus, our Vice President, General Counsel & Corporate Secretary, and Mark E. Bush, our Vice President, Operations (the "First Amendment"). The First Amendment is designed to ensure that the severance agreements satisfy the requirements for an exemption from the application of Section 409A of the United States Internal Revenue Code. The foregoing description of the First Amendment is qualified in its entirety by reference to the full text of the form of the First Amendment, a copy of which is attached to this Form 10-K as Exhibit 10.25 and incorporated by reference herein.

Equity Award Agreements

In connection with our IPO, the Board approved certain forms of stock option agreements and phantom stock unit agreements. On March 21, 2012, the Board approved amendments to such forms of equity award agreements to simplify the tax withholding procedures by (1) creating a single procedure that applies to all persons regardless of whether such person is subject to Section 16 of the Exchange Act and (2) eliminating the requirement that the election with respect to tax withholding obligations be made six months in advance of the withholding date. The amendments to the forms of stock option agreements and phantom stock unit agreements are filed as Exhibits 10.26, 10.27, 10.28, 10.29 and 10.30 to this Form 10-K.

Amendment No. 1 to Tax Sharing Agreement

On March 21, 2012, our Board approved the Lone Pine Resources Inc. 2012 Employee Stock Purchase Plan (the “Purchase Plan”), which is subject to stockholder approval at our 2012 Annual Meeting of Stockholders. In addition, on March 21, 2012, we entered into an amendment to the Tax Sharing Agreement dated May 25, 2012 by and between us and Forest Oil Corporation to permit the issuance of our capital stock pursuant to the Purchase Plan. As amended, the tax sharing agreement permits us to issue up to an aggregate of 10% of the amount of our capital stock outstanding immediately after the IPO pursuant to both the Lone Pine Resources Inc. 2011 Stock Incentive Plan and the Purchase Plan. Amendment No. 1 to the Tax Sharing Agreement is filed as Exhibit 10.31 to this Form 10-K.

PART III

Item 10. Directors Executive Officers and Corporate Governance.

Code of Business Conduct and Ethics

We have adopted a Code of Business Conduct and Ethics for Employees and Officers (“Code”) which covers a wide range of business practices and procedures. The Code represents the code of ethics applicable to our principal executive officer, principal financial officer and principal accounting officer or controller and persons performing similar functions (“senior financial officers”). A copy of the Code is available on our website <http://www.lonepineresources.com>, and a copy will be mailed without charge, upon written request, to Lone Pine Resources Inc., Suite 1100, 640-5th Avenue SW, Calgary, Alberta T2P 3G4, attn: Corporate Secretary. We intend to disclose any amendments to or waivers of the Code on behalf of our senior financial officers on our website, at <http://www.lonepineresources.com>, promptly following the date of the amendment or waiver.

Other

Pursuant to General Instruction G to Form 10-K, we incorporate by reference the remaining information required by this item from the information to be disclosed in our definitive proxy statement for our 2012 Annual Meeting of Stockholders, which will be filed with the SEC within 120 business days of December 31, 2011.

Item 11. Executive Compensation.

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this item the information to be disclosed in our definitive proxy statement for our 2012 Annual Meeting of Stockholders, which will be filed with the SEC within 120 business days of December 31, 2011.

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

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this item the information to be disclosed in our definitive proxy statement for our 2012 Annual Meeting of Stockholders, which will be filed with the SEC within 120 business days of December 31, 2011.

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

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this item the information to be disclosed in our definitive proxy statement for our 2012 Annual Meeting of Stockholders, which will be filed with the SEC within 120 business days of December 31, 2011.

Item 14. Principal Accounting Fees and Services.

Pursuant to General Instruction G to Form 10-K, we incorporate by reference into this item the information to be disclosed in our definitive proxy statement for our 2012 Annual Meeting of Stockholders, which will be filed with the SEC within 120 business days of December 31, 2011.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

- (a) The following documents are filed as a part of this Form 10-K or are incorporated by reference:
- (1) Financial Statements—See Part II, “Item 8, Financial Statements and Supplementary Data.”
 - (2) Financial Statement Schedules—All schedules have been omitted since the required information is not present or not present in amounts sufficient to require submission of the schedule or because the information required is included in the financial statements and notes thereto.
 - (3) Exhibits including those incorporated by reference—The exhibits required to be filed pursuant to Item 601 of Regulation S-K are listed in the Exhibit Index immediately preceding the exhibits filed with this Form 10-K, and such listing is incorporated by reference.

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 on the 22nd day of March, 2012.

LONE PINE RESOURCES INC.

By: /s/ DAVID M. ANDERSON
David M. Anderson
President and Chief Executive Officer

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 in the capacities indicated on the 22nd day of March, 2012.

<u>Signature</u>	<u>Title</u>
<u>/s/ DAVID M. ANDERSON</u> David M. Anderson	President Chief Executive Officer and Director (Principal Executive Officer)
<u>/s/ EDWARD J. BEREZNICKI</u> Edward J. Bereznicki	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
<u>/s/ DAVID M. FITZPATRICK</u> David M. Fitzpatrick	Director
<u>/s/ DALE J. HOHM</u> Dale J. Hohm	Director
<u>/s/ LOYOLA G. KEOUGH</u> Loyola G. Keough	Director
<u>/s/ PATRICK R. McDONALD</u> Patrick R. McDonald	Director
<u>/s/ DONALD MCKENZIE</u> Donald McKenzie	Director
<u>/s/ ROB WONNACOTT</u> Rob Wonnacott	Director

EXHIBIT INDEX

Exhibit No.	Description of Exhibit
3.1	Amended and Restated Certificate of Incorporation of Lone Pine Resources Inc., incorporated herein by reference to Exhibit 3.1 to Amendment No. 5 to Form S-1 for Lone Pine Resources Inc. filed May 3, 2011 (File No. 333-171123).
3.2	Second Amended and Restated Bylaws of Lone Pine Resources Inc., incorporated herein by reference to Exhibit 3.1 to Form 8-K for Lone Pine Resources Inc. filed October 13, 2011 (File No. 001-35191).
4.1	Rights Agreement, incorporated herein by reference to Exhibit 4.1 to Amendment No. 7 to Form S-1 for Lone Pine Resources Inc. filed May 23, 2011 (File No. 333-171123).
4.2	Certificate of Designation of Series A Junior Participating Preferred Stock of Lone Pine Resources Inc., dated May 11, 2011, incorporated herein by reference to Exhibit 4.2 to Amendment No. 7 to Form S-1 for Lone Pine Resources Inc. filed May 23, 2011 (File No. 333-171123).
4.3	Indenture dated February 14, 2012, among Lone Pine Resources Inc., Lone Pine Resources Canada Ltd., Lone Pine Resources (Holdings) Inc., Wiser Delaware LLC, Wiser Oil Delaware, LLC, and U.S. National Bank Association, as trustee, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Lone Pine Resources Inc. filed February 15, 2012 (File No. 001-35191).
4.4	Registration Rights Agreement dated February 14, 2012, among Lone Pine Resources Inc., Lone Pine Resources Canada Ltd., Lone Pine Resources (Holdings) Inc., Wiser Delaware LLC, Wiser Oil Delaware, LLC, and Credit Suisse Securities (USA) LLC, as representative of the Purchasers, incorporated herein by reference to Exhibit 4.2 to Form 8-K for Lone Pine Resources Inc. filed February 15, 2012 (File No. 001-35191).
10.1	Separation and Distribution Agreement dated May 25, 2011, by and among Forest Oil Corporation, Canadian Forest Oil Ltd., and Lone Pine Resources Inc., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Lone Pine Resources Inc. filed June 1, 2011 (File No. 001-35191).
10.2	Transition Services Agreement dated June 1, 2011, by and between Forest Oil Corporation and Lone Pine Resources Inc., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Lone Pine Resources Inc. filed June 1, 2011 (File No. 001-35191).
10.3	Tax Sharing Agreement dated May 25, 2011, by and between Forest Oil Corporation and Lone Pine Resources Inc., incorporated herein by reference to Exhibit 10.4 to Form 8-K for Lone Pine Resources Inc. filed June 1, 2011 (File No. 001-35191).
10.4	Employee Matters Agreement dated May 25, 2011, by and among Forest Oil Corporation, Canadian Forest Oil Ltd., and Lone Pine Resources Inc., incorporated herein by reference to Exhibit 10.5 to Form 8-K for Lone Pine Resources Inc. filed June 1, 2011 (File No. 001-35191).
10.5	Registration Rights Agreement dated June 1, 2011, by and between Forest Oil Corporation and Lone Pine Resources Inc., incorporated herein by reference to Exhibit 10.3 to Form 8-K for Lone Pine Resources Inc. filed June 1, 2011 (File No. 001-35191).

Exhibit No.	Description of Exhibit
10.6	Credit Agreement dated March 18, 2011 among Lone Pine Resources Inc., as parent, Canadian Forest Oil Ltd., as borrower, each of the lenders party thereto and JPMorgan Chase Bank, N.A., Toronto Branch as Administrative Agent, incorporated herein by reference to Exhibit No. 10.6 to Amendment No. 3 to Form S-1 for Lone Pine Resources Inc. filed April 8, 2011 (File No. 333-171123).
10.7	First Amendment dated April 29, 2011 to Credit Agreement dated March 18, 2011 among Lone Pine Resources Inc., as parent, Canadian Forest Oil Ltd., as borrower, each of the lenders party thereto and JPMorgan Chase Bank, N.A., Toronto Branch as Administrative Agent, incorporated herein by reference to Exhibit No. 10.6.1 to Amendment No. 5 to Form S-1 for Lone Pine Resources Inc. filed May 3, 2011 (File No. 333-171123).
10.8	Second Amendment dated September 21, 2011 to Credit Agreement dated March 18, 2011, among Lone Pine Resources Inc., as parent, Lone Pine Resources Canada Ltd., formerly known as Canadian Forest Oil Ltd., as borrower, each of the lenders party thereto and JPMorgan Chase Bank, N.A., Toronto Branch as Administrative Agent, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Lone Pine Resources Inc. filed September 22, 2011 (File No. 001-35191).
10.9	Third Amendment dated February 5, 2012 to Credit Agreement dated March 18, 2011, among Lone Pine Resources Inc., as parent, Lone Pine Resources Canada Ltd., formerly known as Canadian Forest Oil Ltd., as borrower, each of the lenders party thereto and JPMorgan Chase Bank, N.A., Toronto Branch as Administrative Agent, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Lone Pine Resources Inc. filed February 6, 2012 (File No. 001-35191).
10.10	Second Amended and Restated Promissory Note dated March 25, 2010 between Canadian Forest Oil Ltd. and Forest Oil Corporation, incorporated herein by reference to Exhibit 10.9 to Amendment No. 1 to Form S-1 for Lone Pine Resources Inc. filed January 31, 2011 (File No. 333-171123).
10.11	Amendment No. 1 dated May 13, 2010 to Second Amended and Restated Promissory Note dated March 25, 2010 between Canadian Forest Oil Ltd. and Forest Oil Corporation, incorporated herein by reference to Exhibit 10.10 to Amendment No. 1 to Form S-1 for Lone Pine Resources Inc. filed January 31, 2011 (File No. 333-171123).
10.12	Amendment No. 2 dated June 15, 2010 to Second Amended and Restated Promissory Note dated March 25, 2010 between Canadian Forest Oil Ltd. and Forest Oil Corporation, incorporated herein by reference to Exhibit 10.11 to Amendment No. 1 to Form S-1 for Lone Pine Resources Inc. filed January 31, 2011 (File No. 333-171123).
10.13†	Lone Pine Resources Inc. 2011 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Lone Pine Resources Inc. filed October 13, 2011 (File No. 001-35191).
10.14†	Lone Pine Resources Inc. 2011 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.10 to Amendment No. 3 to Form S-1 for Lone Pine Resources Inc. filed April 8, 2011 (File No. 333-171123).
10.15†	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Restricted Stock Agreement, incorporated herein by reference to Exhibit 10.13 to Amendment No. 4 to Form S-1 for Lone Pine Resources Inc. filed April 27, 2011 (File No. 333-171123).

Exhibit No.	Description of Exhibit
10.16†	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Phantom Stock Unit (in lieu of Restricted Stock) for Canadian Director Grantees, incorporated herein by reference to Exhibit 10.14 to Amendment No. 4 to Form S-1 for Lone Pine Resources Inc. filed April 27, 2011 (File No. 333-171123).
10.17†(a)	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Phantom Stock Unit (RSU Award) Agreement for Canadian Employee Grantees, incorporated herein by reference to Exhibit 10.15 to Amendment No. 4 to Form S-1 for Lone Pine Resources Inc. filed April 27, 2011 (File No. 333-171123).
10.18†	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Phantom Stock Unit (SAR Award) Agreement for Canadian Employee Grantees, incorporated herein by reference to Exhibit 10.16 to Amendment No. 4 to Form S-1 for Lone Pine Resources Inc. filed April 27, 2011 (File No. 333-171123).
10.19†	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Performance Unit Award Agreement for Canadian Grantees, incorporated herein by reference to Exhibit 10.17 to Amendment No. 4 to Form S-1 for Lone Pine Resources Inc. filed April 27, 2011 (File No. 333-171123).
10.20†	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Stock Option Agreement for Canadian Grantees, incorporated herein by reference to Exhibit 10.18 to Amendment No. 4 to Form S-1 for Lone Pine Resources Inc. filed April 27, 2011 (File No. 333-171123).
10.21†(b)	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Phantom Stock Unit (RSU Award) Agreement for Canadian Employee Grantees (Cash Only), incorporated herein by reference to Exhibit 10.1 to Form 8-K for Lone Pine Resources Inc. filed June 6, 2011 (File No. 001-35191).
10.22†	Form of Lone Pine Resources Inc. Severance Agreement for Chief Executive Officer, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Lone Pine Resources Inc. filed June 6, 2011 (File No. 001-35191).
10.23†(c)	Form of Lone Pine Resources Inc. Severance Agreement for Executive Officers and Key Employees, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Lone Pine Resources Inc. filed June 6, 2011 (File No. 001-35191).
10.24	Third Amendment to Second Amended and Restated U.S. Credit Agreement and Termination of Second Amended and Restated Canadian Credit Agreement dated May 25, 2011, by and among Forest Oil Corporation, Canadian Forest Oil Ltd., JPMorgan Chase Bank, N.A., Toronto branch, as Canadian administrative agent, JPMorgan Chase Bank, N.A., as global administrative agent, and the lenders named therein, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Lone Pine Resources Inc. filed June 1, 2011 (File No. 001-35191).
10.25†*(d)	Form of First Amendment to the Lone Pine Resources Inc. Severance Agreement for Executive Officers and Key Employees.
10.26†*	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Stock Option Agreement for Canadian Grantees.
10.27†*	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Phantom Stock Unit (RSU Award) Agreement for Canadian Employee Grantees.

Exhibit No.	Description of Exhibit
10.28†*	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Phantom Stock Unit (SAR Award) Agreement for Canadian Employee Grantees.
10.29†*	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Performance Unit Award Agreement for Canadian Grantees.
10.30†*	Lone Pine Resources Inc. 2011 Stock Incentive Plan—Form of Phantom Stock Unit (RSU Award) Agreement for Canadian Employee Grantees (Cash Only).
10.31†*	Amendment No. 1 dated March 21, 2012 to Tax Sharing Agreement dated May 25, 2011 by and between Forest Oil Corporation and Lone Pine Resources Inc.
14.1*	Lone Pine Resources Inc. Code of Business Conduct and Ethics for Members of the Board of Directors (adopted as of March 17, 2011).
14.2*	Lone Pine Resources Inc. Code of Business Conduct and Ethics for Employees and Officers (adopted as of March 17, 2011).
21.1*	List of subsidiaries of Lone Pine Resources Inc.
23.1*	Consent of DeGolyer and MacNaughton.
23.2*	Consent of Ernst & Young LLP.
23.3*	Consent of Ernst & Young LLP.
31.1*	Certification of Principal Executive Officer of Lone Pine Resources Inc. as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Principal Financial Officer of Lone Pine Resources Inc. as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
32.1**	Certifications of Principal Executive Officer and Principal Financial Officer of Lone Pine Resources Inc. pursuant to 18 U.S.C. §1350.
99.1*	Reserves Audit Report of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated February 3, 2012.
101.INS††	XBRL Instance Document.
101.SCH††	XBRL Taxonomy Extension Schema Document.
101.CAL††	XBRL Taxonomy Calculation Linkbase Document.
101.LAB††	XBRL Label Linkbase Document.
101.PRE††	XBRL Presentation Linkbase Document.
101.DEF††	XBRL Taxonomy Extension Definition.

* Filed herewith.

** Not considered to be “filed” for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

† Contract or compensatory plan or arrangement in which directors and/or officers participate.

†† The documents formatted in XBRL (Extensible Business Reporting Language) and attached as Exhibit 101 to this report are deemed not filed as part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act, are deemed not filed for purposes of section 18 of the Exchange Act, and otherwise are not subject to liability under these section

- (a) On October 11, 2011, the Company entered into a Phantom Stock Unit (RSU Award) Agreement for Canadian Employee Grantees pursuant to the Lone Pine Resources Inc. 2011 Stock Incentive Plan with Mark E. Bush.
- (b) On July 1, 2011, the Company entered into a Phantom Stock Unit (RSU Award) Agreement for Canadian Employee Grantees (Cash Only) pursuant to the Lone Pine Resources Inc. 2011 Stock Incentive Plan with Edward J. Bereznicki.
- (c) On June 1, 2011, the Company entered into Severance Agreements with each of David M. Anderson, Douglas W. Axani, Gordon W. Howe and Shona F. Mackenzie. On September 6, 2011 and September 23, 2011, the Company entered into Severance Agreements with each of Charles R. Kraus and Lyle H. Burke, respectively. On October 11, 2011, October 12, 2011 and October 21, 2011, the Company entered into Severance Agreements with each of Mark E. Bush, Edward J. Bereznicki and Shane K. Abel, respectively.
- (d) On March 21, 2012, the Company entered into Amendment No. 1 to the Severance Agreement with each of Charles R. Kraus, our Vice President, General Counsel & Corporate Secretary, and Mark E. Bush, our Vice President, Operations.