FOREST OIL CORP
Form 10-K
February 22, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
(Mark One)

x 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

o 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: 1-13515

FOREST OIL CORPORATION
(Exact Name of Registrant as Specified in Its Charter)

| | |
|---|---|
| State of incorporation: New York | I.R.S. Employer Identification No. 25-0484900 |
| 707 17th Street - Suite 3600 - Denver, Colorado | 80202 |
| (Address of Principal Executive Offices) | (Zip Code) |

Registrant's telephone number, including area code: (303) 812-1400
Securities registered pursuant to Section 12(b) of the Act:

| Title of Each Class | Name of Each Exchange on which Registered |
|---|---|
| Common Stock, Par Value $.10 Per Share | New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x
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 x No o
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 x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
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 x | Accelerated filer o | Non-accelerated filer o<br>(Do not check if a smaller | Smaller reporting company o |

reporting company)

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

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 $3,024,434,519 (based on the closing price of such stock).

There were 117,210,156 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 16, 2012.

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

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PART I

Item 1. Business.

General

Throughout this Annual Report on Form 10-K, we use the terms "Forest," "Company," "we," "our," and "us" to refer to Forest Oil Corporation and its subsidiaries. In the following discussion, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). See "Forward-Looking Statements," below, for more details. We also use a number of terms used in the oil and gas industry. See "Glossary of Oil and Gas Terms" for the definition of certain terms.

Forest is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Forest's total estimated proved oil and gas reserves as of December 31, 2011 were approximately 1,904 Bcfe. At December 31, 2011, approximately 97% of Forest's estimated proved oil and gas reserves were in the United States.

In June 2011, Forest completed an initial public offering of approximately 18% of the common stock of its then wholly-owned subsidiary, Lone Pine Resources Inc. (“Lone Pine”), which held Forest’s ownership interests in its Canadian operations. On September 30, 2011, Forest distributed, or spun-off, its remaining 82% ownership in Lone Pine to Forest's shareholders of record as of September 16, 2011, by means of a special stock dividend of Lone Pine common shares. As a result of the spin-off, Lone Pine is reported as a discontinued operation throughout this Form 10-K. See "Acquisition and Divestiture Activities" below for more information on the initial public offering and subsequent spin-off of Lone Pine.

Strategy

Following the spin-off of Lone Pine, Forest implemented a long-term operating strategy intended to increase shareholder value through the achievement of organic production and reserve growth while maintaining a capital expenditure budget that approximates cash flow from operating activities. Forest believes measured growth can be achieved through this strategy by focusing capital expenditures primarily on developing Forest’s core operational areas located in the Texas Panhandle, East Texas / North Louisiana, and in the Eagle Ford Shale in South Texas. In addition, our growth may be supplemented from time to time through opportunistic acquisitions. We endeavor to execute this strategy as follows:

Exploit and develop resource plays for measured production and reserve growth while maintaining a capital expenditure budget that approximates cash flow from operating activities. In our efforts to grow production and reserves, we plan to continue to apply the latest technologies to our resource plays, including horizontal drilling and multi-stage hydraulic fracture stimulation techniques. We believe these technologies provide for efficient production and reserve growth from our diverse portfolio of shale and conventional oil and gas acreage positions. Our core operational areas have a large number of remaining commodity-diverse drilling locations, providing what we believe to be are repeatable development opportunities. In 2012, due to a low natural gas price environment, we intend to devote the majority of our exploration and development expenditures to oil and liquids projects, including approximately 50% in the Texas Panhandle where liquids-rich Granite Wash and shallow oil intervals are targeted. Further, due to the low natural gas price environment, we expect our capital expenditures will exceed our cash flows in 2012.

Focus on operational control, cost efficiencies, and high-margin projects. Our development efforts are focused in areas where we have concentrated land positions, a large drilling inventory, and operational control, which allow us to optimize our development plans and, therefore, reduce costs. Furthermore, our diverse portfolio allows us to allocate capital to projects with the highest margins, which currently include oil or liquids-rich drilling prospects. Our concentrated land positions, operational control, and focus on cost and margin allow us to achieve economies of scale and potentially provide for higher rates of return on invested capital.

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 operational areas and in new areas emphasizing grass roots leasing efforts at attractive entry cost, with a preference for liquids-rich hydrocarbon prospects. We also plan to pursue a measured exploration program in these areas through the utilization of our strong internal technical staff. As economic conditions permit, we intend to divest assets that do not fit our primary business strategy, including those without significant development opportunities.

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Maintain financial flexibility. We intend to maintain a strong liquidity position to successfully execute our growth strategy through the application of budget controls and prudent financial management. Further, we intend to focus on reducing our debt levels relative to our estimated proved reserves and EBITDA and will consider joint ventures, divestitures, and other means to increase our financial flexibility.

## Core Operational Areas

Forest's core areas consist of a well-balanced portfolio of tight-gas sands, carbonates, and shale plays with multiple stacked-pay opportunities in the United States that have exposure to oil, natural gas liquids, and natural gas. Initial vertical delineation drilling in many of our core areas has established the existence of consistent geologic trends, creating what we believe to be low-risk, repeatable development opportunities. Forest initially exploited the majority of its core operational areas through vertical development, but with the emergence of new drilling and completion technology, Forest has transitioned the development of a number of these plays to horizontal development. Through the application of horizontal drilling, Forest seeks to enhance initial production rates and estimated ultimate recoveries while focusing on reducing drilling costs. Our primary areas of focus in 2012 will be in the Texas Panhandle, East Texas / North Louisiana, and in the Eagle Ford Shale in South Texas.

### Texas Panhandle

We have approximately 109,000 net acres in the Texas Panhandle, establishing Forest as one of the top acreage holders in this area. The area provides for excellent horizontal drilling opportunities targeting multiple liquids-rich Granite Wash intervals as well as oil-rich objectives including the Tonkawa, Cleveland, and Missourian Wash formations. We drilled our first horizontal wells in the area in 2009, leveraging our vertical delineation database of over 600 wells to determine the most attractive intervals to initiate a horizontal drilling campaign. Based on significant results achieved through the 2009 horizontal drilling program, Forest increased its horizontal development rig count from one to five rigs from 2009 to 2010, developing known productive intervals and establishing new prospective intervals for future drilling efforts. In total, Forest has successfully tested seven liquids-rich intervals as prospective for horizontal development in the Granite Wash. With the favorable price of condensate and natural gas liquids relative to natural gas, this liquids-rich play provides superior rates of return compared to other natural gas plays in North America. Additionally, during 2011, Forest successfully tested two prospective oil intervals, including the shallow Cleveland formation and the Missourian Wash (Hogshooter) formation, that expands the oil drilling potential within the Texas Panhandle. In total, Forest has tested 11 intervals as prospective for horizontal development in the Texas Panhandle. In 2012, we plan to run a five to six rig drilling program targeting the Granite Wash and other prospective intervals, including the Cleveland and Missourian Wash formations.

### East Texas / North Louisiana

We have approximately 125,000 net acres in the East Texas / North Louisiana area. The area provides for both horizontal and vertical drilling opportunities targeting multiple stacked-pay intervals, including the Cotton Valley, Haynesville, Pettit, and other formations. In 2010, our development program was focused in the Haynesville/Bossier Shale in North Louisiana where we drilled 20 horizontal wells that had average 24-hour initial production rates of 16 MMcfe/d. In an effort to optimize recovery from Haynesville/Bossier Shale wells, Forest instituted a restricted flow rate production program in late-2010. Under this program, initial production rates from the last six wells were curtailed at 11 to 15 MMcfe/d. In 2011, Forest reduced drilling and completions efforts in the Haynesville/Bossier Shale in North Louisiana and the Cotton Valley in East Texas due to increasing service costs. By the end of 2011, Forest re-entered the plays as a result of reductions in drilling and completion costs in the region, positive performance from its restricted rate production program in the Haynesville/Bossier Shale, and liquids-rich drilling opportunities in the Cotton Valley. In 2012, we plan to run a two rig drilling program in North Louisiana and East Texas.

### South Texas—Eagle Ford Shale

We have approximately 103,000 net acres in the Eagle Ford Shale, primarily located in Gonzales County in South Texas. The area provides Forest with access to the oil-bearing section of the Eagle Ford and is expected to yield an oil development opportunity through the application of horizontal drilling and completion technologies. We commenced the drilling of our first horizontal well in the Eagle Ford oil window at the end of 2010 and expanded the program in 2011 to focus on the optimization of our development operations. This optimization included taking core samples, acquiring 3-D seismic, the utilization of micro-seismic during horizontal well completions, and testing different sections of the Eagle Ford Shale, all with the goal of finding the optimal section in the Eagle Ford in which to land the lateral and the most effective and efficient methods to complete the wells. Through Forest's optimization efforts undertaken in 2011 in the Eagle Ford Shale, we believe that we can ultimately generate economic production rates and recoveries. In 2012, we plan to run a one rig drilling program in the Eagle Ford Shale.

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Acquisition and Divestiture Activities

We pursue acquisitions that meet our criteria for investment returns and are consistent with our North American onshore low-risk development focus, and we pursue divestitures of non-core assets to upgrade our portfolio and further increase our operational efficiencies. Acquisitions in and around our existing core areas enable us to leverage our cost control abilities, technical expertise, and existing land and infrastructure positions. In general, our acquisition program has focused on acquisitions of properties that have substantial development drilling opportunities and undeveloped acreage positions. The following sets forth our significant acquisitions and divestitures over the last several years.

Acquisitions

During 2011 and early 2012, we acquired 126,000 gross acres (114,500 net) prospective for oil production in the Permian Basin. The acreage position was established in areas prospective for both the Wolfcamp Shale in Crockett County, Texas, where Forest has 57,500 gross acres (51,500 net) and the Wolfbone zones in Pecos and Reeves Counties, Texas, where Forest has 68,500 gross acres (63,000 net). We believe this acreage position allows us access to significant oil drilling opportunities that we intend to pursue in 2012.

In September 2008, we acquired producing oil and natural gas properties located in our Texas Panhandle and East Texas / North Louisiana core areas from Cordillera Texas, L.P. for approximately $570 million in cash and 7.25 million shares of our common stock, valued at approximately $360 million. As of the closing date of the acquisition, the assets included approximately 350 Bcfe of estimated proved reserves and 85,000 net acres.

In June 2007, we acquired The Houston Exploration Company ("Houston Exploration") in a cash and stock transaction totaling approximately $1.5 billion including the assumption of Houston Exploration's debt. Houston Exploration was an independent natural gas and oil producer engaged in the exploration, development, and acquisition of natural gas and oil reserves in North America. At the time of the acquisition, we estimated the Houston Exploration proved reserves to be 653 Bcfe. Pursuant to the terms and conditions of the agreement and plan of merger, Forest paid total merger consideration of $750 million in cash and issued approximately 24 million shares of our common stock, valued at approximately $726 million.

Divestitures

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 Resources Inc. (“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 to Forest's shareholders. The initial public offering of Lone Pine occurred in June 2011, with Forest retaining approximately 82% of the outstanding shares of Lone Pine's common stock. Lone Pine used the net proceeds from the offering, along with borrowings under its credit facility, to pay approximately $29 million to Forest, as partial consideration for the contribution to Lone Pine of Forest’s interests in the Canadian operations, and to repay an intercompany note and intercompany advances and accrued interest of approximately $401 million. The spin-off of Forest's remaining shares of Lone Pine to Forest shareholders was completed on September 30, 2011.

In 2009, we sold all of our oil and gas properties located in the Permian Basin in West Texas and New Mexico as well as other oil and gas properties in the U.S. for approximately $933 million in cash. We estimated the proved reserves associated with these properties were 551 Bcfe at the closings of the relevant transactions.

In August 2007, we sold all of our assets located in Alaska to Pacific Energy Resources Ltd. ("PERL"), with such assets estimated to have proved reserves of 173 Bcfe at the time of closing. Total consideration received for the assets included $400 million in cash as well as 10 million shares of PERL common stock and a zero coupon senior subordinated note from PERL due 2014 at a principal amount of $61 million.

In March 2006, we completed a spin-off of our offshore Gulf of Mexico operations by means of a special dividend, which consisted of a pro rata spin-off of all outstanding shares of a Forest subsidiary that held our offshore Gulf of Mexico assets, to holders of record of Forest common stock as of the close of business on February 21, 2006. Immediately following the spin-off, the Forest subsidiary was merged with a subsidiary of Mariner Energy, Inc. ("Mariner"), at which time the 50.6 million shares included in the spin-off were exchanged for an equal number of Mariner common shares. Mariner's common stock commenced trading on the New York Stock Exchange ("NYSE") on March 3, 2006. We estimated the proved reserves associated with the spin-off to be 313 Bcfe at the time of closing.

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Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2011, based on the Henry Hub price of $4.12 per MMBtu for natural gas and the West Texas Intermediate price of $96.08 per barrel for oil, each of which represents the unweighted arithmetic average of the first-day-of-the-month prices during the twelve-month period prior to December 31, 2011. See—"Preparation of Reserves Estimates" below and Note 15 to the Consolidated Financial Statements for additional information regarding our estimated proved reserves.

| | Estimated Proved Reserves | | | |
|---|---|---|---|---|
| | Natural Gas (MMcf) | Oil (MBbls) | Natural Gas Liquids (MBbls) | Total (MMcfe)[(1)] |
| Developed: | | | | |
| United States | 814,160 | 14,149 | 23,170 | 1,038,074 |
| Italy | — | — | — | — |
| Total developed | 814,160 | 14,149 | 23,170 | 1,038,074 |
| Undeveloped: | | | | |
| United States | 582,356 | 17,444 | 21,259 | 814,574 |
| Italy | 51,738 | — | — | 51,738 |
| Total undeveloped | 634,094 | 17,444 | 21,259 | 866,312 |
| Total estimated proved reserves | 1,448,254 | 31,593 | 44,429 | 1,904,386 |

(1) Oil and natural gas liquids are converted to gas-equivalents using a conversion of six Mcf "equivalent" per barrel of oil or natural gas liquids. This conversion is based on energy equivalence and not price equivalence. For 2011, the average of the first-day-of-the-month gas price was $4.12 per Mcf, and the average of the first-day-of-the-month oil price was $96.08 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 23 Mcf per barrel of oil and approximately 13 Mcf per barrel of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2011).

As of December 31, 2011, Forest had estimated proved reserves of 1,904 Bcfe, an increase of 2% compared to 1,868 Bcfe of estimated proved reserves from continuing operations at December 31, 2010. Of the December 31, 2011 total, 1,853 Bcfe (97%) were in the United States and 52 Bcfe (3%) were in Italy. During 2011, we added 301 Bcfe of estimated proved reserves through extensions and discoveries primarily driven by our 2011 drilling activity in the Texas Panhandle and South Texas, with such additions partially offset by property sales of 21 Bcfe and negative revisions of 120 Bcfe, including 47 Bcfe related to proved undeveloped locations ("PUD") that were written off pursuant to the Securities and Exchange Commission's ("SEC") five year development limitation on PUDs.

As of December 31, 2011, proved undeveloped reserves were estimated to be 866 Bcfe, or 45% of estimated proved reserves, compared to 730 Bcfe, or 39% of estimated proved reserves from continuing operations as of December 31, 2010. The net increase of 136 Bcfe was primarily due to the recording of horizontal PUDs in the Texas Panhandle and South Texas. We invested $182 million to convert 71 Bcfe of our December 31, 2010 PUD reserves to proved developed reserves during 2011. We have no material concentrations of PUDs in individual fields or countries that we expect to remain undeveloped for five years past the date they were initially disclosed as PUDs, except with respect to a concentration of reserves in Italy related to four natural gas wells (which make up all of the 52 Bcfe of proved reserves in Italy).

In 2007, we drilled, completed, and tested two natural gas wells in Italy. At December 31, 2007, we recorded proved developed reserves attributable to those two wells as well as proved undeveloped reserves attributable to two undrilled offset locations. Since 2007, we have been engaged with various governmental and jurisdictional agencies in a process to obtain approval of an environmental impact assessment (“EIA”) and a production license needed to initiate production from the developed reserves, and to start full field development. The process has proceeded at a considerably slower pace than we anticipated and has still not reached a conclusion. At December 31, 2011, we determined to reclassify our proved developed reserves associated with the two wells already drilled and completed in

Italy to the proved undeveloped category. At the present time, we anticipate obtaining approval of the EIA and production license during 2012. If we are successful in that respect, we would expect to initiate production in Italy in early 2015, following the construction of a needed desulfurization plant and pipeline. During the initial two years of production, the volumes that we may produce in Italy under the anticipated regulatory conditions will be limited to approximately 12 MMcf/day. This curtailment, coupled with the expected plant capacity, will likely cause us to delay drilling the two undeveloped locations until 2017.

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Preparation of Reserves Estimates

Reserves estimates included in this Annual Report on Form 10-K are prepared by Forest's internal staff of engineers with significant consultation with internal geologists and geophysicists. The reserves estimates are based on production performance and data acquired remotely or in wells, and are guided by petrophysical, geologic, geophysical, and reservoir engineering models. Access to the database housing reserves information is restricted to select individuals from our engineering department. Moreover, new reserves estimates and significant changes to existing reserves are reviewed and approved by various levels of management, depending on their magnitude. Proved reserves estimates are reviewed and approved by the Vice President, Corporate Engineering, and at least 80% of our proved reserves, based on net present value, are audited by independent reserve engineers (see "Independent Audit of Reserves" below) prior to review by the Audit Committee. In connection with its review, the Audit Committee meets privately with personnel from DeGolyer and MacNaughton, the independent petroleum engineering firm that audits our reserves, to confirm that DeGolyer and MacNaughton has not identified any concerns or issues relating to the audit and maintains independence. In addition, Forest's internal audit department randomly selects a sample of new reserves estimates or changes made to existing reserves and tests to ensure that they were properly documented and approved.

Forest's Vice President, Corporate Engineering, Michael Dern, has 34 years of experience in oil and gas exploration and production and has held this position at Forest since July 2011. Prior to that time, Mr. Dern held positions of increasing responsibility at Forest since joining the company in 2001, including most recently Reservoir Engineering Manager for the Eastern Region. Prior to joining Forest, Mr. Dern held various positions in reservoir engineering and corporate planning with Phillips Petroleum, Midcon Exploration, and Apache Corporation. Mr. Dern received a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines.

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, natural gas liquids, and natural gas that cannot be measured in an exact manner, and the accuracy of any reserves 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, natural gas liquids, and natural gas quantities ultimately recovered will vary from reserves estimates. See Part I, Item 1A—"Risk Factors," below for a description of some of the risks and uncertainties associated with our business and reserves.

Independent Audit of Reserves

We engage independent reserve engineers to audit a substantial portion of our reserves. Our audit procedures require the independent engineers to prepare their own estimates of proved reserves for fields comprising at least 80% of the aggregate net present value, discounted at 10% per annum ("NPV"), of our year-end proved reserves for each country in which proved reserves have been recorded. The fields selected for audit also must comprise at least 80% of Forest's fields based on the NPV of such fields and a minimum of 80% of the NPV added during the year through discoveries, extensions, and acquisitions. The procedures prohibit exclusions of any fields, or any part of a field, that comprises part of the top 80%. The independent reserve engineers compare their own estimates to those prepared by Forest. Our audit guidelines require Forest's internal estimates, which are used for financial reporting and disclosure purposes, to be within 5% of the independent reserve engineers' quantity estimates. The independent reserve audit is conducted based on reserve definition and cost and price parameters specified by the SEC.

For the years ended December 31, 2011, 2010, and 2009, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the year ended December 31, 2011, DeGolyer and MacNaughton independently audited estimates relating to properties constituting over 83% of our reserves by NPV as of December 31, 2011. When compared on a field-by-field basis, some of Forest's estimates of proved reserves were greater and some were less than the estimates prepared by DeGolyer and MacNaughton. However, in the aggregate, Forest's estimates of total proved reserves were within 5% of DeGolyer and MacNaughton's aggregate estimate of proved reserves for the fields audited. The lead technical person at DeGolyer and MacNaughton primarily responsible for overseeing the audit of our reserves is a Registered Professional Engineer in the State of Texas, is a member of the

International Society of Petroleum Engineers and the American Association of Petroleum Geologists, and has in excess of 37 years of experience in oil and gas reservoir studies and reserves evaluations.

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Drilling Activities

The following table summarizes the number of wells drilled during 2011, 2010, and 2009 related to our continuing operations, 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 21 gross (12 net) wells in progress in the United States. During 2011, we drilled a total of 127 gross (68 net) wells, of which 26 were classified as exploratory and 101 were classified as development. Our 2011 drilling program, which primarily consisted of horizontal wells, achieved a 97% success rate.

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2011 | | 2010 | | 2009 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Development wells: | | | | | | |
| United States: | | | | | | |
| Productive | 101 | 44 | 75 | 38 | 76 | 47 |
| Non-productive[1] | — | — | 5 | 4 | 6 | 4 |
| Total development wells | 101 | 44 | 80 | 42 | 82 | 51 |
| Exploratory wells: | | | | | | |
| United States: | | | | | | |
| Productive | 22 | 21 | 24 | 16 | 23 | 14 |
| Non-productive[1] | 4 | 3 | 5 | 4 | — | — |
| Total | 26 | 24 | 29 | 20 | 23 | 14 |
| Italy: | | | | | | |
| Non-productive[1] | — | — | — | — | 1 | 1 |
| Total | — | — | — | — | 1 | 1 |
| Total exploratory wells | 26 | 24 | 29 | 20 | 24 | 15 |

(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).

Oil and Gas Wells and Acreage

Productive Wells

The following table summarizes our productive wells as of December 31, 2011, all of which are located in the United States and Italy. 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. As of December 31, 2011, Forest owned interests in 78 gross wells containing multiple completions.

| | United States | | Italy | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Gas | 3,585 | 2,612 | 2 | 2 | 3,587 | 2,614 |
| Oil | 364 | 229 | — | — | 364 | 229 |
| Total | 3,949 | 2,841 | 2 | 2 | 3,951 | 2,843 |

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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. A majority of our developed acreage is subject to mortgage liens securing our bank credit facility. 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 2%, 1%, and 11% of our net undeveloped acreage in the United States was held under leases that will expire in 2012, 2013, and 2014, respectively, if not extended by exploration or production activities.

| | Developed Acreage | | Undeveloped Acreage | |
|---|---|---|---|---|
| Location | Gross | Net | Gross | Net |
| United States(1) | 683,167 | 430,397 | 530,082 | 336,889 |
| South Africa(2) | — | — | 2,771,695 | 1,474,542 |
| Italy | — | — | 107,043 | 86,507 |
| Total | 683,167 | 430,397 | 3,408,820 | 1,897,938 |

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(1) Concentrations of net acres in the United States as of December 31, 2011 include: 109,000 net acres in the Texas Panhandle; 125,000 net acres in East Texas / North Louisiana; 232,000 net acres in the South Texas (including 103,000 in the Eagle Ford Shale); 89,000 net acres in the Permian Basin in West Texas; and 72,000 net acres in the Uintah Basin in Utah.

(2) We applied to the South African government to convert one existing prospecting sublease (known as Block 2C) into an Exploration Right, and for a Production Right covering the geographic area of our other prospecting sublease (known as Block 2A). The Block 2A Production Right was granted in August 2009. The first term of this Production Right is for up to five years during which we, and our partners, are permitted to develop the local market for natural gas. Required work programs are minimal and full development remains contingent at our and our partners' option. The Block 2C Exploration Right conversion was executed in April 2010. It requires a work program of one exploration well during the initial three-year period, with additional work obligations expected in any further exploration periods. We continue to pursue commercial development of the Ibhubesi field discovery in South Africa, including continued efforts toward securing gas sales contracts.

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Production, Average Sales Prices, and Production Costs

The following table reflects production, average sales price, and production cost information for the years ended December 31, 2011, 2010, and 2009 for continuing operations. Forest's Italian geographical area has not had any production and Forest does not have any fields that individually contain 15% or more of the Company's total estimated proved reserves.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Natural Gas: | | | |
| Production volumes (MMcf) | 88,497 | 101,346 | 116,029 |
| Average sales price (per Mcf) | $3.71 | $3.99 | $3.33 |
| Liquids: | | | |
| Oil and condensate: | | | |
| Production volumes (MBbls) | 2,491 | 2,357 | 3,397 |
| Average sales price (per Bbl) | $96.22 | $76.08 | $56.87 |
| Natural gas liquids: | | | |
| Production volumes (MBbls) | 3,154 | 3,589 | 3,012 |
| Average sales price (per Bbl) | $42.91 | $34.54 | $25.17 |
| Total liquids: | | | |
| Production volumes (MBbls) | 5,645 | 5,946 | 6,409 |
| Average sales price (per Bbl) | $66.43 | $51.01 | $41.97 |
| Total production volumes (MMcfe) (1) | 122,367 | 137,022 | 154,483 |
| Average sales price (per Mcfe) | $5.75 | $5.16 | $4.24 |
| Production costs (per Mcfe): | | | |
| Lease operating expenses | $.81 | $.67 | $.77 |
| Transportation and processing costs | .11 | .10 | .08 |
| Production costs excluding production and property taxes (per Mcfe) | .92 | .77 | .86 |
| Production and property taxes | .33 | .32 | .26 |
| Total production costs (per Mcfe) | $1.25 | $1.09 | $1.12 |

(1) Oil and natural gas liquids are converted to gas-equivalents using a conversion of six Mcf "equivalent" per barrel of oil or natural gas liquids. This conversion is based on energy equivalence and not price equivalence. For 2011, the average of the first-day-of-the-month gas price was $4.12 per Mcf, and the average of the first-day-of-the-month oil price was $96.08 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 23 Mcf per barrel of oil and approximately 13 Mcf per barrel of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2011).

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 or NYMEX WTI monthly averages and is typically sold at the wellhead. Our natural gas liquids production is typically sold under term agreements at prices based on postings at large fractionation facilities. 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. We had no material delivery commitments as of February 16, 2012.

Competition

Forest encounters competition in all aspects of its business, including acquisition of properties and oil and gas leases, marketing oil and gas, 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.

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## Industry Regulation

Our oil and gas operations are subject to various U.S. federal, state, and local laws and regulations and local and national laws and regulations in Italy and South Africa. These laws and regulations may be changed in response to economic or political conditions. Matters subject to current governmental regulation or pending legislative or regulatory changes include bonding 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, taxation, and the use of derivative hedging instruments. Our operations are also subject to permit requirements for the drilling of wells and regulations relating to the location of wells, the method of drilling and the casing of wells, surface use and restoration of properties on which wells are located, and the plugging and abandonment of wells. 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, and the issuance of injunctions that could delay, limit, or prohibit certain of our operations. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies may restrict the rates of flow of oil and gas wells below actual production capacity. Further, a significant spill from one of our facilities could have a material adverse effect on our results of operations, competitive position, or financial condition. The laws in the United States, Italy, and South Africa regulate, among other things, 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. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. Certain of our operations are conducted on federal land pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed BLM regulations and orders (which are subject to change by the BLM). In addition to permits required from other agencies, lessees must obtain a permit from the BLM prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production, and the removal of facilities. Under certain circumstances, the BLM may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") imposes reporting and other requirements on our business and operations, including with respect to payments made to U.S. and foreign governments related to our oil and gas exploration and development activities. The legislation also imposes new requirements and oversight on our derivatives transactions, including potential new clearing, margin, and position limits requirements. Significant regulations are required to be promulgated by the SEC and the Commodity Futures Trading Commission to implement these requirements and provide certain exemptions for qualified end-users. Although Forest does not anticipate it will be affected differently than other producers of oil and natural gas, the new requirements are likely to impose additional reporting obligations on us with respect to the use of derivative instruments to hedge against commercial risks related to fluctuations in oil and gas commodity prices and interest rates. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future. The imposition of these types of requirements or limitations could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activities.

Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission, and the courts. We cannot predict when or whether any such proposal, or any additional new legislative or regulatory proposal, may become effective. No material portion of Forest's business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the federal government.

## Environmental and Climate Change Regulation

We are subject to stringent national, state, provincial, and local laws and regulations in the jurisdictions where we operate relating to environmental protection, including the manner in which various substances such as 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 closure 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 additional compliance costs, 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

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been used for the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, 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 pluggings or pit closures or other actions of a remedial nature to prevent future contamination.

Our operations produce wastewater that is disposed via injection in underground wells. These wells are regulated under the Safe Drinking Water Act (the "SDWA") and similar state and local laws. The underground injection well program under the SDWA requires permits from the United States Environmental Protection Agency ("EPA") or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations, and restricts the types and quantities of fluids that may be injected. We believe that our disposal well operations comply with all applicable requirements under the SDWA and similar state and local laws. However, a change in the regulations or the inability to obtain permits for new injection wells in the future may affect the Company's ability to dispose of produced waters and ultimately increase the cost of the Company's operations.

Hydraulic fracturing is an important process used in the completion of our oil and gas wells. The process involves the injection of water, sand, and chemicals under pressure into low-permeability formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. Various state and local governments have implemented or are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, requirements for disclosure of chemical constituents, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. For instance, in December 2011, the states of Texas and Colorado adopted far-reaching rules that require the public disclosure of chemicals used in the hydraulic fracturing process, with the Texas rules applicable to fracturing treatments on wells with initial drilling permits issued on or after February 1, 2012, and the Colorado rules applicable to fracturing treatments performed on or after April 1, 2012. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, Congress has considered legislation to regulation under the SDWA. If adopted, such legislation would establish an additional level of regulation and impose additional costs on our operations. See Part I, Item 1A—"Risk Factors—We may incur significant costs related to environmental and other governmental laws and regulations, including those related to "hydraulic fracturing," that may materially affect our operations" below.

Nearly half of the states in the U.S., either individually or through multi-state initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases (“GHGs”). Also, the Supreme Court held in Massachusetts et al v. EPA (2007) that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act, and subsequently in December 2009, the EPA determined that GHG emissions present an endangerment to public health and the environment because such emissions, according to the EPA, are contributing to warming of the earth's atmosphere and other climate changes. These findings allow the EPA to implement regulations that would restrict GHG emissions under existing provisions of the Clean Air Act. On November 8, 2010, the EPA finalized GHG reporting requirements for the petroleum and natural gas industries. Under this final rule, owners or operators of facilities that contain petroleum and natural gas systems, as defined by the rule, and emit 25,000 metric tons or more of GHGs per year per basin (expressed as carbon dioxide equivalents) will report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. Owners or operators will collect emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, record keeping, and reporting defined in the final rule. For purposes of the rule, an onshore petroleum and natural gas production facility is generally defined as all petroleum and natural gas equipment associated with all petroleum or natural gas production wells and $CO_2$ enhanced oil recovery operations that are under common ownership or control, including leased, rented, and contracted activities, by an onshore petroleum and natural gas production owner or operator and that are located within a single hydrocarbon basin as defined by the American Association of Petroleum Geologists. The rule is estimated to require reporting from approximately 2,800 facilities, covering 85% of the total GHG emissions from the U.S. petroleum and natural gas industries, including all of Forest's facilities, with modeling reporting beginning in late 2012 and actual data reporting beginning in 2013. We expect these new rules to result in increased compliance costs on our operations. In addition, these rules, and any other new rules and regulations addressing GHG emissions, could result in additional operating restrictions.

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 in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future. We have established internal guidelines

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to be followed in order to comply with environmental laws and regulations in the United States and other relevant international jurisdictions. 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.

Employees

As of December 31, 2011, we had 676 employees. None of our employees is currently represented by a union for collective bargaining purposes.

Geographical Data

Forest operates in one industry segment, oil and gas exploration and production, and has one reportable geographical business segment, the United States.

Offices

Our corporate office is located in leased space at 707 17$^{th}$ Street, Denver, Colorado. We maintain an office in Houston, Texas, and also lease or own field offices in the areas in which we conduct operations.

Title to Properties

Title to our oil and gas properties is subject to royalty, overriding royalty, carried, net profits, working, and similar interests customary in the oil and gas industry. Under the terms of our bank credit facility, we have granted the lenders a lien on the substantial majority 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. Forest's 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 by Forest.

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Annual Report on 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 SEC's website at http://www.sec.gov.

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 Bbl 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. Acreage that is 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.

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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.
MBoe.    Thousand barrels of crude oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.
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.
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.
NYMEX.    New York Mercantile Exchange.
Productive wells.    Producing wells and wells that are mechanically capable of production.
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 twelve-month period prior to the end of the reporting period, 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.

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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 or present value of estimated future net revenues. 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 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.

Available Information

Forest's website address is http://www.forestoil.com. Available on our website, free of charge, are Forest's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, reports on Forms 3, 4, and 5 filed on behalf of directors and officers, as well as amendments to these reports. These materials are available as soon as reasonably practicable after such materials are electronically filed with or furnished to the SEC.

Also posted on Forest's website, and available in print upon written request of any shareholder addressed to the Secretary of Forest, at 707 17th Street, Suite 3600, Denver, Colorado 80202, are Forest's Corporate Governance Guidelines, the charters for each of the committees of our Board of Directors (including the charters of the Audit Committee, Compensation Committee, and Nominating and Corporate Governance Committee), and codes of ethics for our directors and employees entitled "Code of Business Conduct and Ethics" and "Proper Business Practices Policy," respectively.

Forward-Looking Statements

The information in this Annual Report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. Forward-looking statements are statements other than statements of historical or present facts, that address activities, events, outcomes, and other matters that Forest plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates, or anticipates (and other similar expressions) will, should, or may occur in the future. Generally, the words "expects," "anticipates," "targets," "goals," "projects," "intends," "plans," "believes," "seeks," "estimates," "may," "will," "could," "should," "future," "potential," "continue," the negative of such words or other variations of such words, and similar expressions identify forward-looking statements. Similarly, statements that describe our strategies, initiatives, objectives, plans or goals are forward-looking. These forward-looking statements are based on our current intent, belief, expectations, estimates, projections, forecasts, and assumptions about future events and are based on currently available information as to the outcome and timing of future events. These statements are not guarantees of future performance.

These forward-looking statements appear in a number of places and include statements with respect to, among other things:

- estimates of our oil and natural gas reserves;
- estimates of our future oil and natural gas production, including estimates of any increases or decreases in our production;
- our future financial condition and results of operations;

- our future revenues, cash flows, and expenses;
- our access to capital and our anticipated liquidity;
- our future business strategy and other plans and objectives for future operations;

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- our outlook on oil and natural gas prices;
- the amount, nature, and timing of future capital expenditures, including future development costs;
- our ability to access the capital markets to fund capital and other expenditures;
- our assessment of our counterparty risk and the ability of our counterparties to perform their future obligations; and
- the impact of federal, state, and local political, regulatory, and environmental developments in the United States and certain foreign locations where we conduct business operations.

We believe the expectations, estimates, projections, forecasts, and assumptions reflected in our forward-looking statements are reasonable, but we can give no assurance that they will prove to be correct. We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, and sale of oil and gas. See "Competition," "Industry Regulation," and "Environmental and Climate Change Regulation" above, as well as Part I, Item 1A—"Risk Factors," Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources," and Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk" for a description of various, but by no means all, factors that could materially affect our ability to achieve the anticipated results described in the forward-looking statements.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information to reflect events or circumstances after the filing of this report with the SEC, except as required by law. All forward-looking statements, expressed or implied, included in this Annual Report on Form 10-K and attributable to Forest are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we may make or persons acting on our behalf may issue.

## 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.

Oil and natural gas prices are volatile. Declines in commodity prices have adversely affected, and in the future may adversely affect, our results of operations, cash flows, financial condition, access to the capital markets, the economic viability of our reserves, and our ability to reinvest in order to maintain or grow our asset base.

Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to a variety of factors that are beyond our control. Approximately 76% of our estimated proved reserves at December 31, 2011 were natural gas, causing us to be particularly dependent on prices for natural gas.

During the fourth quarter of 2011 and continuing into 2012, natural gas prices declined to ten year lows. Further deterioration in prices may mean that it will not be economical to drill or produce natural gas from some of our existing properties, and we may be required to curtail, or stop completely, our production activities in those areas. A continuation of low natural gas prices, or a significant decline in oil prices, may have the following effects on our business:

- impairing our financial condition, liquidity, or ability to fund planned capital expenditures;
- limiting our access to sources of capital, such as equity and debt; or
- prohibiting us from developing our current properties, or from growing our asset base.

We have substantial indebtedness, and we may incur more debt in the future. Our leverage may materially affect our operations and financial condition.

As of December 31, 2011, we had long-term indebtedness of $1.7 billion, including $105 million drawn under our bank

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credit facility. The governing documents of our debt contain covenants and restrictions that require that we meet certain financial tests and place restrictions on the incurrence of additional indebtedness.

Our level of debt may have several important effects on our business and operations; among other things, it may:

- require us to use a significant portion of our cash flow to service the obligations, which could limit our flexibility in planning for and reacting to changes in our business, and reduce the amount available to reinvest in order to maintain or grow our asset base;

- adversely affect the credit ratings assigned by third party rating agencies, which have in the past and may in the future downgrade their ratings of our debt and other obligations;

- limit our access to the capital markets;

- increase our borrowing costs, and impact the terms, conditions, and restrictions contained in our debt agreements, including the addition of more restrictive covenants;

- place us at a disadvantage compared to companies in our industry that have less debt and other financial obligations; and

- make us more vulnerable to economic downturns, volatile oil and natural gas prices, and adverse developments in our business.

If our cash flow is not sufficient to service our debt and other obligations or to meet the financial covenants, we may be required to refinance the debt, sell assets, or sell shares of our stock—all on terms that we do not find attractive, if it can be done at all.

We are a relatively small company and therefore may not be able to compete effectively.

Compared to many of the companies in our industry, we are a small company. We face difficulties in competing with the larger companies. The costs of doing business in the exploration and production industry, including such costs as those required to explore new oil and natural gas plays, to acquire new acreage, and to develop attractive oil and natural gas projects, are significant. Our limited size can place us at a disadvantage with respect to funding such costs. Our limited size also means that we are more vulnerable to commodity price volatility and overall industry cycles, are less able to absorb the burden of changes in laws and regulations, and that poor results in any single exploration, development, or production play can have a disproportionately negative impact on us. Our size can also impair our ability to attract and retain staff and maintain competitive technical capabilities.

Our estimates of oil and natural gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves and our financial condition.

The proved oil and natural gas reserves information and the related future net revenues information contained in this report represent only estimates, which are prepared by our internal staff of engineers and the majority of which are audited by DeGolyer and MacNaughton, an independent petroleum engineering firm. Estimating quantities of proved oil and natural gas reserves is a complex, inexact process and depends on a number of interpretations of technical data and various factors and assumptions, including assumptions required by the SEC as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds. As a result, these estimates are inherently imprecise. Any significant inaccuracies or changes in our assumptions, or changes in operating conditions could cause the estimated quantities and net present value of the estimated reserves to be significantly different.

At December 31, 2011, approximately 45% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserves estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule, and results associated with these properties may not be as estimated.

You should not assume that any present value of future net cash flows from our estimated proved reserves represents the market value of our oil and natural gas reserves.

If we are not able to replace reserves, we will not be able to sustain or grow production.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we replace the reserves we produce through successful development,

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exploration or acquisition, our proved reserves and production will decline over time.

We do not always find commercially productive reserves through our drilling operations. The seismic data and other technologies that we use when drilling wells do not allow us to determine conclusively prior to drilling a well whether oil or natural gas is present or can be produced economically. Moreover, the costs of drilling, completing, and operating wells are often uncertain. Our drilling activities, therefore, may result in the total loss of our investment or a return on investment significantly below expectation.

Most of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

A sizable portion of our acreage is currently undeveloped. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, cash flow, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

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

We deliver the majority of our oil and natural gas through gathering facilities that we do not own or 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. If we experience interruptions or loss of pipeline capacity or access to gathering systems that impact a substantial amount of our production, it could have an adverse impact on our cash flow.

Drilling is a high-risk activity that could result in substantial losses for us.

We conduct a portion of our drilling activities through a wholly-owned drilling subsidiary that operates drilling rigs and provides services to us and third parties. The activities conducted by the drilling subsidiary are subject to many risks, including well blow-outs, cratering and explosions, pipe failures, fires, uncontrollable flows of oil, natural gas, brine, or well fluids, other environmental hazards, and risks outside of our control, including, among other things, the risk of natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases. 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. 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 fully adequate to cover other losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

Our use of hedging transactions could reduce our cash flow and/or result in reported losses.

We periodically enter into hedging agreements for a portion of our anticipated oil, natural gas, and NGL production. Our commodity hedging agreements are limited in duration, usually for periods of one year or less; however, we sometimes enter into hedges for longer periods. Should commodity prices increase after we have entered into a hedging transaction, our cash flows will be lower than they would have been had the hedge not been in place.

For financial reporting purposes, we do not use hedge accounting, thus we are required to record changes in the fair value of our hedging instruments through our earnings rather than through other comprehensive income had we elected to use hedge accounting. As a consequence, we may report material unrealized losses or gains on our hedging agreements prior to their expiry. The amount of the actual realized losses or gains will differ and will be based on the actual prices of the commodities on the settlement dates as compared to the hedged prices contained in the hedging agreements. As a result, our periodic financial results will be subject to fluctuations related to our derivative instruments.

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted by Congress is expected to, among other things, impose new requirements and oversight on derivatives transactions, including new clearing and margin requirements. While implementing regulations are yet to be completed by federal regulatory agencies, to the extent they are applicable to us or our derivatives counterparties, we may incur increased costs and cash collateral requirements that could affect our ability effectively to hedge risks associated with our business.

We may incur significant costs related to environmental and other governmental laws and regulations, including those related to "hydraulic fracturing," that may materially affect our operations.

Our oil and natural gas operations are subject to various U.S. federal, state, and local laws and regulations, and local and national laws and regulations in Italy and South Africa. Many of the laws and regulations to which our operations are subject

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include those relating to the protection of the environment. We could incur material costs, including clean-up costs, fines and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, present or future environmental laws and regulations.

We routinely utilize hydraulic fracturing, which is an important and common practice used to stimulate production of hydrocarbons from tight, or low-permeability formations. State oil and gas commissions typically regulate the process. However, several federal entities, including the EPA, have also recently asserted potential regulatory authority over hydraulic fracturing. Some states, such as Texas, have adopted, and some states, including others in which we operate, are considering adopting, regulations that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing operations. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to operate. Restrictions on, or increased costs of, hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

The credit risk of financial institutions could adversely affect us.

We have entered into transactions with counterparties in the financial services industry, including commercial banks, insurance companies, and their affiliates. These transactions expose us to credit risk in the event of default of our counterparty, principally with respect to hedging agreements but also insurance contracts and bank lending commitments. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. See Note 9 to Consolidated Financial Statements for a more complete discussion of credit risk with respect to our derivative instruments.

We may record impairments of our asset values, which could negatively affect our results of operations and net worth.

We follow the full cost method of accounting for our oil and natural gas properties. Depending upon the twelve-month average oil and natural gas prices at the end of each quarterly and annual period when we are required to test the carrying value of our assets using full cost accounting rules, we may be required to write-down the value of our oil and natural gas properties if the present value of the after-tax future cash flows, adjusted as required, from our oil and natural gas properties falls below the net book value of these properties, adjusted as required. Such write-downs are referred to as “ceiling test write-downs.” We have in the past experienced ceiling test write-downs with respect to our oil and natural gas properties. Future non-cash ceiling test write-downs could negatively affect our results of operations and net worth. 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.”

We also test goodwill for impairment annually or when circumstances indicate that an impairment may exist. If the book value of our reporting unit exceeds the estimated fair value of that reporting unit, an impairment charge will occur, which would negatively impact our results of operations and net worth. See Part II, Item 7—“Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies, Estimates, Judgments, and Assumptions—Goodwill.”

We may face liabilities related to the pending bankruptcy of Pacific Energy Resources, Ltd.

In August 2007, we closed on the sale of our oil and gas assets in Alaska (the "Alaska Assets") to Pacific Energy Resources, Ltd. ("PERL"). In March 2009, PERL filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. PERL requested, and the bankruptcy court has approved, abandonment of PERL's interests in certain of the Alaska Assets. The remaining working interest owners in the Alaska Assets have made the assertion that, in its role as assignor of the Alaska Assets, Forest should be held liable for any contractual obligations of PERL with respect to the Alaska Assets, including obligations related to operating costs and for costs associated with the final plugging and decommissioning of wells and production facilities. For example, Forest has been joined as a defendant in a dispute over which companies should bear the cost of decommissioning and abandoning a platform and its associated wells, located in Cook Inlet, Alaska. See Part I, Item 3—"Legal Proceedings" for a discussion of material litigation involving the Alaska Assets.

Item 1B. Unresolved Staff Comments.

As of January 25, 2012, all SEC staff comments regarding our periodic or current reports that had been received prior to 180 days before December 31, 2011 had been resolved.

## Item 2. Properties.

Information on Properties is contained in Item 1 of this Annual Report on Form 10-K.

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## Item 3. Legal Proceedings.

In August 2007, Forest sold all of its Alaska assets to Pacific Energy Resources Ltd. and its related entities ("PERL"). On March 9, 2009, PERL filed for bankruptcy. As part of the plan of liquidation of its bankruptcy, PERL "abandoned" its interests in many of the Alaska assets sold to it by Forest, including the Trading Bay Unit and Trading Bay Field ("Trading Bay"). At the time of the abandonment of PERL's interests in Trading Bay, Union Oil Company of California ("Unocal") was the operator of those assets. On December 2, 2010, Unocal filed a lawsuit styled Union Oil Company of California v. Forest Oil Corporation in Anchorage District Court, Alaska. Forest has removed the case to federal district court in Anchorage, Alaska. In the lawsuit, the plaintiff complains about PERL's abandonment of Trading Bay and states that PERL has failed to pay approximately $48 million in joint interest billings owed on those properties to date from the time PERL owned them. The plaintiff further claims that Forest is liable for PERL's share of all joint interest billings owed on Trading Bay, in arrears and in the future, because (1) Forest was the predecessor party to the contracts governing the operations at Trading Bay, (2) Unocal did not agree that, in conjunction with Forest's sale of its Alaska assets, Forest would be released of its obligations under the Trading Bay contracts, and (3) PERL has defaulted on the joint interest billings owed on Trading Bay since October 2008. As of December 31, 2011, Unocal sold its interest in the Trading Bay assets, including its claims against Forest, to Hilcorp Energy Company. Although we are unable to predict the final outcome of this case, we believe that the allegations of this lawsuit are without merit, and we intend 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.

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Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of February 16, 2012.

| Name | Age | Years with Forest | Office(1) |
|---|---|---|---|
| H. Craig Clark | 55 | 11 | President and Chief Executive Officer, and a member of the Board of Directors since July 2003. Mr. Clark joined Forest in September 2001 and served as President and Chief Operating Officer through July 2003. Mr. Clark was employed by Apache Corporation, an oil and gas exploration and production company, from 1989 to 2001, where he served in various management positions including Executive Vice President—U.S. Operations and Chairman and Chief Executive Officer of Pro Energy, an affiliate of Apache. |
| Michael N. Kennedy | 37 | 11 | Executive Vice President and Chief Financial Officer since December 2009. Mr. Kennedy joined Forest in February 2001. He served as Senior Financial Analyst until April 2003, at which time he became Manager of Investor Relations. Mr. Kennedy served in that role until November 2005 when he became Managing Director of Capital Markets and Treasurer and in April 2008 assumed the role of Vice President—Finance and Treasurer. Prior to joining Forest, Mr. Kennedy worked for Arthur Andersen as a member of its audit and business advisory practice. |
| J.C. Ridens | 56 | 8 | Executive Vice President and Chief Operating Officer since November 2007. Since joining Forest in April 2004, Mr. Ridens has served as Senior Vice President for the Gulf Region, the Southern Region and the Western Region. From 2001 to 2004, Mr. Ridens was employed by Cordillera Energy Partners, LLC, as Vice President of Operations and Exploitation. From 1996 to 2001, he served in various capacities at Apache Corporation. |
| Cecil N. Colwell | 61 | 23 | Senior Vice President, Worldwide Drilling since May 2004. Between 2000 and May 2004, Mr. Colwell served as our Vice President, Drilling, and from 1988 to 2000 he served as our Drilling Manager, Gulf Coast. |
| Cyrus D. Marter IV | 48 | 10 | Senior Vice President, General Counsel and Secretary since November 2007. Mr. Marter served as Vice President, General Counsel and Secretary from January 2005 to November 2007, as Associate General Counsel from October 2004 to January 2005, and as Senior Counsel from June 2002 until October 2004. Prior to joining Forest, Mr. Marter was a partner in the law firm of Susman Godfrey L.L.P. in Houston, Texas. |
| Glen J. Mizenko | 49 | 11 | Senior Vice President, Eastern Region since June 2011. Mr. Mizenko joined Forest in January 2001 as Manager Corporate Development and New Ventures. In October 2003, he was promoted to the position of Director, Business Development. In May 2005, he was promoted to Vice President, Business Development, and in May 2007 was again promoted to SeniorVice President, Business Development and Corporate Engineering. Prior to joining Forest, Mr. Mizenko held various positions in reservoir engineering, reserves reporting, development planning, and operations management with Shell Oil, Benton Oil & Gas, and British Borneo Oil and Gas PLC. |
| Victor A. Wind | 38 | 7 | |

| | | | |
|---|---|---|---|
| | | | Senior Vice President, Chief Accounting Officer and Corporate Controller since December 2009. Mr. Wind previously served as Vice President, Chief Accounting Officer and Corporate Controller since May 2009. He joined Forest as Corporate Controller in January 2005. Mr. Wind was previously employed by Evergreen Resources, Inc. from July 2001 to December 2004. He served in various management positions during this period, including Director of Financial Reporting and Controller. From 1997 to 2001, he served in various capacities at BDO Seidman, LLP. |
| Ronald C. Nutt | 54 | 5 | Vice President, Southern Region since July 2007. Prior to joining Forest, from March 2007 to July 2007, Mr. Nutt worked for Constellation Energy Group, and from January 2003 to March 2007 at Scotia Waterous as Vice President, Engineering. |

(1) Officers are appointed to serve for one-year terms at the board meeting immediately following the last annual meeting, or until their death, resignation, or removal from office, whichever first occurs.

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PART II

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

Common Stock

Forest has one class of common shares outstanding, its common stock, par value $.10 per share ("Common Stock"). Forest's Common Stock is traded on the New York Stock Exchange under the symbol "FST." On February 16, 2012, our Common Stock was held by 653 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange composite tape, as well as adjusted prices per share of the Common Stock that reflect the stock dividend distributed by Forest on September 30, 2011. There were no cash dividends declared on the Common Stock in 2010 or 2011. On February 16, 2012, the closing price of Forest Common Stock was $14.40.

| | | Common Stock | | Common Stock (As Adjusted)(1) | |
|---|---|---|---|---|---|
| | | High | Low | High | Low |
| 2010 | First Quarter | $30.08 | $22.61 | $21.35 | $16.05 |
| | Second Quarter | 32.81 | 22.85 | 23.29 | 16.22 |
| | Third Quarter | 31.89 | 24.83 | 22.64 | 17.63 |
| | Fourth Quarter | 39.32 | 29.69 | 27.91 | 21.08 |
| 2011 | First Quarter | $40.23 | $32.39 | $28.56 | $22.99 |
| | Second Quarter | 38.65 | 24.56 | 27.44 | 17.44 |
| | Third Quarter | 28.22 | 14.14 | 20.03 | 10.04 |
| | Fourth Quarter | 17.22 | 8.88 | 17.22 | 8.88 |

(1) On September 30, 2011, Forest completed the spin-off of Lone Pine by means of a special stock dividend distributed to all shareholders of Forest Common Stock. The stock dividend consisted of .61248511 shares of Lone Pine for each outstanding share of Forest Common Stock. Based on this ratio, the value of the stock dividend to Forest shareholders is deemed by Forest to be equal to $4.18, or the average of the high and low intraday sales prices per share of Lone Pine common stock on September 30, 2011 multiplied by .61248511.

The prices shown in the "As Adjusted" column above for the first quarter of 2010 through the third quarter of 2011 have been adjusted to reflect the stock dividend paid on September 30, 2011. The ratio used for this historical price adjustment is .2901. This represents the ratio of (a) $4.18 to (b) $14.41, the average of the high and low intraday sales prices per share of Forest Common Stock on September 30, 2011.

Dividend Restrictions

Forest's present or future ability to pay dividends is governed by (i) the provisions of the New York Business Corporation Law, (ii) Forest's Restated Certificate of Incorporation and Bylaws, (iii) the indentures concerning Forest's 8½% senior notes due 2014 and Forest's 7¼% senior notes due 2019, and (iv) Forest's bank credit facility dated as of June 30, 2011. The provisions in the indentures pertaining to these senior notes and in the bank credit facility limit our ability to make restricted payments, which include dividend payments. On March 2, 2006, Forest distributed a special stock dividend in connection with the spin-off of its offshore Gulf of Mexico operations and, as noted above, on September 30, 2011, Forest distributed a special stock dividend in connection with the spin-off of Lone Pine; however, Forest has not paid cash dividends on its Common Stock during the past five years. The future payment of cash dividends, if any, on the Common Stock is within the discretion of the Board of Directors and will depend on Forest's earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that Forest will pay any cash dividends. For further information regarding our equity securities, our ability to pay dividends on our Common Stock, and the spin-off of Lone Pine, see Notes 3 and 5 to the Consolidated Financial Statements.

Unregistered Sales of Equity Securities

We did not make any sales of unregistered equity securities during the quarter ended December 31, 2011.

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Issuer Purchases of Equity Securities

The table below sets forth information regarding repurchases of our Common Stock during the quarter ended December 31, 2011. The shares repurchased represent shares of our Common Stock that employees elected to surrender to Forest to satisfy their tax withholding obligations upon the vesting of shares of restricted stock and phantom stock units that are settled in shares. Forest does not consider this a share buyback program.

| Period | Total # of Shares Purchased | Average Price Per Share | Total # of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum # (or Approximate Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| October 2011 | 8,970 | $11.00 | — | — |
| November 2011 | 2,523 | 15.16 | — | — |
| December 2011 | 2,109 | 13.66 | — | — |
| Fourth Quarter Total | 13,602 | 12.19 | — | — |

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2006 (and the reinvestment of dividends thereafter) in each of Forest Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. We believe that the Dow Jones U.S. Exploration and Production Index is meaningful, because it is an independent, objective view of the performance of other similarly-sized energy companies.

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The information in this Annual Report on Form 10-K appearing under the heading "Stock Performance Graph" is being furnished pursuant to Item 201(e) of Regulation S-K and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act.

Item 6. Selected Financial Data.

The following table sets forth selected financial and operating data of Forest as of and for each of the years in the five-year period ended December 31, 2011. This data should be read in conjunction with Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations," below, and the Consolidated Financial Statements and Notes thereto contained elsewhere in this report. We have completed several oil and gas property acquisition and divestiture transactions that affect the comparability of the results for the years presented below. See Part I, Item 1—"Business—Acquisition and Divestiture Activities" and Note 2 to the Consolidated Financial Statements for more information on acquisitions and divestitures.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2008 | 2007 |
| | (In Thousands, Except Per Share Amounts, Volumes, and Prices) | | | | |
| FINANCIAL DATA | | | | | |
| Oil, natural gas, and NGL sales[1] | $703,531 | $707,692 | $655,579 | $1,396,669 | $892,818 |
| Net earnings (loss) from continuing operations | $98,260 | $189,662 | $(793,789) | $(1,081,446) | $106,198 |
| Net earnings (loss) from discontinued operations[2] | 44,569 | 37,859 | (129,344) | 55,123 | 63,108 |
| Net earnings (loss) | $142,829 | $227,521 | $(923,133) | $(1,026,323) | $169,306 |
| Less: net earnings attributable to noncontrolling interest[2] | 4,987 | — | — | — | — |
| Net earnings (loss) attributable to Forest Oil Corporation | $137,842 | $227,521 | $(923,133) | $(1,026,323) | $169,306 |
| Basic earnings (loss) per share:[3] | | | | | |
| Earnings (loss) from continuing operations | $.86 | $1.68 | $(7.61) | $(12.07) | $1.38 |
| Earnings (loss) from discontinued operations | .35 | .33 | (1.24) | .61 | .82 |
| Basic earnings (loss) per common share | $1.21 | $2.01 | $(8.85) | $(11.46) | $2.20 |
| Diluted earnings (loss) per share:[3] | | | | | |
| Earnings (loss) from continuing operations | $.85 | $1.67 | $(7.61) | $(12.07) | $1.35 |
| Earnings (loss) from discontinued operations | .34 | .33 | (1.24) | .61 | .81 |
| Diluted earnings (loss) per common share | $1.19 | $2.00 | $(8.85) | $(11.46) | $2.16 |
| Total assets[1] | $3,381,151 | $3,070,197 | $3,169,054 | $4,555,903 | $4,903,834 |
| Long-term debt[1] | $1,693,044 | $1,869,372 | $2,022,514 | $2,641,246 | $1,639,911 |
| Shareholders' equity | $1,193,113 | $1,352,787 | $1,079,154 | $1,672,912 | $2,411,811 |
| OPERATING DATA[1] | | | | | |
| Annual production: | | | | | |
| Natural gas (MMcf) | 88,497 | 101,346 | 116,029 | 118,120 | 82,963 |

| | | | | | |
|---|---|---|---|---|---|
| Oil (MBbls) | 2,491 | 2,357 | 3,397 | 3,778 | 4,504 |
| NGLs (MBbls) | 3,154 | 3,589 | 3,012 | 3,151 | 2,381 |
| Average sales price: | | | | | |
| Natural gas (per Mcf) | $3.71 | $3.99 | $3.33 | $7.54 | $5.95 |
| Oil (per Bbl) | $96.22 | $76.08 | $56.87 | $96.85 | $67.91 |
| NGLs (per Bbl) | $42.91 | $34.54 | $25.17 | $44.54 | $39.32 |

(1) Amounts reported relate to continuing operations only. See below for more information regarding discontinued operations.

(2) On June 1, 2011, Forest completed the initial public offering of approximately 18% of the common stock of its then wholly-owned subsidiary, Lone Pine Resources Inc., which held Forest's ownership interests in its Canadian operations. On September 30, 2011, Forest distributed, or spun-off, the remaining 82% of Lone Pine by means of a special stock dividend to Forest's shareholders. Lone Pine's results are reported as discontinued operations throughout this Annual Report on Form 10-K.

(3) In June 2008, the Financial Accounting Standards Board issued authoritative accounting guidance that addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method. This guidance was effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, Forest adopted this guidance as of January 1, 2009. All prior period earnings per share data presented has been adjusted retrospectively to conform to the provisions of this guidance.

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

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 in Part I, Item 1 under the heading "Forward-Looking Statements." Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed in Part I, Item 1A—"Risk Factors," and elsewhere in this Annual Report on Form 10-K. Historical statements made herein are accurate only as of the date of filing of this Annual Report on Form 10-K with the SEC, and may be relied upon only as of that date. The following discussion and analysis should be read in conjunction with Forest's Consolidated Financial Statements and the Notes to Consolidated Financial Statements.

Forest is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Our total estimated proved reserves as of December 31, 2011, were approximately 1,904 Bcfe. At December 31, 2011, approximately 97% of our estimated proved reserves were in the United States. Having spun-off our Canadian operations on September 30, 2011, we currently conduct our operations in one reportable geographical segment - the United States. Our core operational areas are in the Texas Panhandle, the East Texas / North Louisiana area, and the Eagle Ford Shale in South Texas. See Item 1—"Business" for a discussion of our business strategy and core operational areas of focus.

In December 2010, we announced our intention to separate our Canadian operations through an initial public offering of up to 19.9% of the common stock of our then wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which would hold our ownership interests in our Canadian operations, followed by a distribution, or spin-off, of the remaining shares of Lone Pine held by us to our shareholders. The offering occurred in June 2011, whereby we retained approximately 82% of the outstanding shares of Lone Pine's common stock. Lone Pine used the net proceeds from the offering, along with borrowings under its credit facility, to pay us approximately $29 million, as partial consideration for our contribution to Lone Pine of our interests in the Canadian operations, and to repay an intercompany note and intercompany advances and accrued interest of approximately $401 million. The spin-off of our remaining shares of Lone Pine to our shareholders was completed on September 30, 2011. As a result of the spin-off, Lone Pine's results of operations are reported as discontinued operations in our Consolidated Statements of Operations for all periods presented.

2011 Highlights

Forest's 2011 highlights are as follows:

- Completed an initial public offering and the subsequent spin-off of Lone Pine to Forest shareholders. Each Forest shareholder of record on September 16, 2011 received approximately .6125 shares of Lone Pine stock for every share of Forest stock held.

- Drilled or participated in 127 gross (68 net) wells in the United States in 2011 including 68 gross (33 net) horizontal wells in the Texas Panhandle with 20 gross wells targeting two new oil zones and three additional liquids-rich gas intervals, bringing the total number of productive intervals to 11 in the Texas Panhandle.

- Continued the initial development of our acreage in the Eagle Ford Shale oil window with the drilling of 15 wells focusing on optimizing the development of the resource. This optimization included taking core samples, acquiring 3-D seismic, the utilization of micro-seismic during horizontal well completion, and testing different sections of the Eagle Ford Shale.

- Initiated the acquisition of undeveloped leaseholds in the Permian Basin in West Texas. As of February 21, 2012 we have acquired over 126,000 gross acres (114,500 net) in the area at an average cost of approximately $1,300 per acre. The acreage position includes 51,500 net acres prospective for the Wolfcamp shale in Crockett County, Texas and 63,000 net acres prospective for the Wolfbone intervals in Pecos and Reeves Counties, Texas.

Recent Trends and 2012 Outlook

Beginning in the second half of 2008 and continuing throughout 2011, 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 plan on natural

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gas prices improving significantly in 2012. As a result, as we did in 2011, we plan to direct the majority of our exploration and development capital expenditures in 2012 to more liquids-rich prospects. See Item 1—"Business—Core Operational Areas" for a summary of our core operational areas of focus.

Results of Operations

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands, Except per Mcfe and per Share Data) | | |
| Oil, natural gas, and NGL sales from continuing operations | $703,531 | $707,692 | $655,579 |
| Realized equivalent sales price (per Mcfe) | 5.75 | 5.16 | 4.24 |
| Net earnings (loss) from continuing operations | 98,260 | 189,662 | (793,789) |
| Diluted earnings (loss) per common share from continuing operations | .85 | 1.67 | (7.61) |
| Adjusted EBITDA from continuing operations[1] | 550,865 | 619,101 | 726,529 |

(1) In addition to reporting net earnings (loss) from continuing operations as defined under generally accepted accounting principles ("GAAP"), we also present Adjusted EBITDA from continuing operations, which is a non-GAAP performance measure. See "—Reconciliation of Non-GAAP Measure" at the end of this Item 7 for a reconciliation of Adjusted EBITDA from continuing operations to reported net earnings (loss) from continuing operations, which is the most directly comparable financial measure calculated and presented in accordance with GAAP.

Our net earnings (loss) from continuing operations and diluted earnings (loss) per share from continuing operations presented in the table above were primarily impacted by changes in oil, natural gas, and NGL production volumes and prices, changes in realized and unrealized derivative gains and, in 2009, a non-cash ceiling test write-down of $1.4 billion. See below for further discussion of these items. Adjusted EBITDA from continuing operations, which excludes the effects of ceiling test write-downs and other non-cash items, was also primarily impacted by changes in oil, natural gas, and NGL production volumes and prices for the periods presented, as well as changes in realized derivative gains.

Management's analysis of the individual components of the changes in our annual results follows.

Oil and Natural Gas Volumes and Revenues

Oil, natural gas, and natural gas liquids ("NGL") sales volumes, revenues, and average sales prices from continuing operations for the years ended December 31, 2011, 2010, and 2009, are set forth in the table below.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Sales volumes: | | | |
| Natural gas (MMcf) | 88,497 | 101,346 | 116,029 |
| Oil (MBbls) | 2,491 | 2,357 | 3,397 |
| NGL (MBbls) | 3,154 | 3,589 | 3,012 |
| Totals (MMcfe) | 122,367 | 137,022 | 154,483 |
| Revenues (In Thousands): | | | |
| Natural gas | $328,510 | $404,415 | $386,581 |
| Oil | 239,695 | 179,312 | 193,185 |
| NGL | 135,326 | 123,965 | 75,813 |
| Totals | $703,531 | $707,692 | $655,579 |
| Average sales price per unit: | | | |
| Natural gas ($/Mcf) | $3.71 | $3.99 | $3.33 |
| Oil ($/Bbl) | 96.22 | 76.08 | 56.87 |
| NGL ($/Bbl) | 42.91 | 34.54 | 25.17 |

| | | | |
|---|---|---|---|
| Totals | $5.75 | $5.16 | $4.24 |

Our reported oil, natural gas, and NGL sales volumes from continuing operations decreased 11% in 2011 compared to

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2010 primarily due to a decrease in natural gas production, which resulted from our decision to reduce capital expenditures for dry gas wells in response to declining natural gas prices. In 2011, we redirected capital expenditures from dry gas well development towards liquids and oil-rich prospects, including the early-stage development of our Eagle Ford oil play and the acquisition of new leaseholds in the Permian Basin prospective for oil development. Oil and natural gas revenues were essentially flat between 2010 and 2011, primarily due to an increase in oil and NGL prices that was offset by a decrease in natural gas production and prices.

Our reported oil, natural gas, and NGL sales volumes from continuing operations decreased 11% in 2010 compared to 2009. The decrease was due to oil and gas property divestitures that occurred primarily in late 2009 partially offset by production increases attributable to new wells drilled in 2010. Oil and natural gas revenues in 2010 were $708 million, an 8% increase as compared to $656 million in 2009. Oil and natural gas revenues increased due to the 22% increase in the average realized sales price per Mcfe, partially offset by the decrease in sales volumes discussed above.

The revenues and average sales prices reflected in the table above exclude the effects of commodity derivative instruments since we have elected not to designate our derivative instruments as cash flow hedges. See—"Realized and Unrealized Gains and Losses on Derivative Instruments" below for more information on gains and losses relating to our commodity derivative instruments.

Production Expense

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands, Except per Mcfe Data) | | |
| Production expense: | | | |
| Lease operating expenses | $99,158 | $92,394 | $119,472 |
| Production and property taxes | 40,632 | 43,656 | 40,147 |
| Transportation and processing costs | 13,728 | 13,242 | 12,855 |
| Production expense | $153,518 | $149,292 | $172,474 |
| Production expense per Mcfe: | | | |
| Lease operating expenses | $.81 | $.67 | $.77 |
| Production and property taxes | .33 | .32 | .26 |
| Transportation and processing costs | .11 | .10 | .08 |
| Production expense per Mcfe | $1.25 | $1.09 | $1.12 |

Lease Operating Expenses

Lease operating expenses in 2011 were $99 million, or $.81 per Mcfe, compared to $92 million, or $.67 per Mcfe, in 2010. The $.14 per Mcfe increase in 2011 compared to 2010 was primarily due to an increase in water handling costs and an increase in the number of producing oil properties that have higher average per-unit operating costs. Lease operating expenses were $92 million, or $.67 per Mcfe, in 2010 compared to $119 million, or $.77 per Mcfe, in 2009. The decrease in total and per-unit lease operating expenses was primarily due to oil and gas property divestitures that occurred during late 2009. The properties divested had higher average per-unit operating costs as compared to the properties we retained.

Production and Property Taxes

Production and property taxes, which primarily consist of severance taxes paid on the value of the oil, natural gas, and NGLs sold, were 5.8%, 6.2%, and 6.1% of oil, natural gas, and NGL revenues for the years ended December 31, 2011, 2010, and 2009, respectively. Normal fluctuations occur in the percentage between periods based upon the approval of incentive tax credits in Texas, changes in tax rates, and changes in the assessed values of oil and gas properties and equipment for purposes of ad valorem taxes.

Transportation and Processing Costs

Transportation and processing costs were $14 million, or $.11 per Mcfe, in 2011, $13 million, or $.10 per Mcfe, in 2010, and $13 million, or $.08 per Mcfe, in 2009.

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General and Administrative Expense

The following table summarizes the components of general and administrative expense from continuing operations for the periods indicated.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands, Except Per Mcfe Data) | | |
| Stock-based compensation costs | $35,706 | $31,475 | $27,801 |
| Other general and administrative costs | 75,792 | 76,018 | 78,983 |
| General and administrative costs capitalized | (46,393) | (42,607) | (41,530) |
| General and administrative expense | $65,105 | $64,886 | $65,254 |
| General and administrative expense per Mcfe | $.53 | $.47 | $.42 |

General and administrative expense was $65 million in each of the years presented. Stock-based compensation costs and general and administrative costs capitalized under the full cost method of accounting increased in 2011 due to the recognition of $12 million ($7 million of expense, net of capitalized amounts) of costs in the third quarter of 2011 due to the spin-off of Lone Pine, which caused the forfeiture restrictions to lapse on a portion of each outstanding restricted stock award, thus requiring the immediate recognition of compensation cost. This increase in stock-based compensation costs was partially offset by a decrease in stock-based compensation costs due to a decline in our stock price in 2011. The percentage of general and administrative costs capitalized remained consistent between the three years presented, ranging between 39% and 42%.

Depreciation, Depletion, and Amortization

The following table summarizes depreciation, depletion, and amortization expense from continuing operations for the periods indicated.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands, Except Per Mcfe Data) | | |
| Depreciation, depletion, and amortization expense | $219,684 | $187,973 | $247,158 |
| Depreciation, depletion, and amortization expense per Mcfe | $1.80 | $1.37 | $1.60 |

Depreciation, depletion, and amortization expense ("DD&A") increased $.43 per Mcfe to $1.80 in 2011 compared to $1.37 in 2010. The increase in DD&A is primarily due to ceiling test write-downs recorded as of December 31, 2008 and March 31, 2009 as well as the sale of oil and gas assets in the fourth quarter of 2009, which together reduced our DD&A rate to $1.25 in the first quarter of 2010. Our depletion rate has steadily increased thereafter as we have added proved oil and natural gas reserves to our depletable base at per-unit rates that have exceeded $1.25 per Mcfe.

Ceiling Test Write-Down of Oil and Gas Properties

Pursuant to the ceiling test limitation prescribed by the SEC for companies using the full cost method of accounting, Forest recorded a non-cash ceiling test write-down for its United States cost center totaling $1.4 billion in the first quarter 2009. The write-down was a result of significant declines in oil and natural gas prices in the first quarter of 2009. See—"Critical Accounting Policies, Estimates, Judgments and Assumptions—Full Cost Method of Accounting."

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Interest Expense

The following table summarizes interest expense from continuing operations for the periods indicated.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| Interest costs | $160,014 | $161,139 | $173,258 |
| Interest costs capitalized | (10,259) | (11,248) | (12,175) |
| Interest expense | $149,755 | $149,891 | $161,083 |

Interest expense totaled $150 million in both 2011 and 2010. In December 2011, we redeemed $285 million of 8% senior notes using cash on hand and borrowings under our credit facility, with such redemption expected to result in lower total interest costs in 2012. Interest expense in 2010 totaled $150 million compared to $161 million in 2009. The $11 million decrease in interest expense was primarily due to a decrease in average debt levels in 2010 compared to 2009. In January 2010, we redeemed $150 million of 7¾% senior notes. In addition, in December 2009, we repaid all amounts outstanding under our credit facility. Interest costs capitalized relate to our investments in significant unproved acreage positions that are under development.

In order to effectively reduce the concentration of fixed-rate debt anticipated after the completion of our 2009 oil and gas property divestiture program and the related reduction in our credit facility balance, we entered into fixed-to-floating interest rate swaps in the first quarter of 2009 under which we have swapped, as of December 31, 2011, $500 million in notional amount at an 8.5% fixed rate for an equal notional amount at a weighted-average interest rate equal to the 1-month LIBOR plus approximately 5.9%. We recognized realized gains under these interest rate swaps of $11 million during each of the years ended December 31, 2011 and 2010 and $7 million during the year ended December 31, 2009. These gains are recorded as realized gains on derivatives rather than as a reduction to interest expense since we have not elected to use hedge accounting. See Note 9 to the Consolidated Financial Statements for more information on our interest rate derivatives.

Realized and Unrealized Gains and Losses on Derivative Instruments

The table below sets forth realized and unrealized gains and losses on derivatives from continuing operations recognized under "Costs, expenses, and other" in our Consolidated Statements of Operations for the periods indicated. See Note 8 and Note 9 to the Consolidated Financial Statements for more information on our derivative instruments.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| Realized losses (gains) on derivatives, net: | | | |
| Oil | $12,584 | $3,825 | $(11,632) |
| Natural gas | (78,247) | (103,587) | (285,576) |
| NGL | 28,128 | — | — |
| Interest | (11,442) | (12,450) | (10,958) |
| Subtotal realized | (48,977) | (112,212) | (308,166) |
| Unrealized (gains) losses on derivatives, net: | | | |
| Oil | (10,297) | 18,978 | 35,771 |
| Natural gas | (22,931) | (47,078) | 139,728 |
| NGL | (4,314) | 9,710 | — |
| Interest | (1,545) | (19,530) | 519 |
| Subtotal unrealized | (39,087) | (37,920) | 176,018 |
| Realized and unrealized gains on derivatives, net | $(88,064) | $(150,132) | $(132,148) |

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Other, Net

The table below sets forth the components of "Other, net" from continuing operations for the periods indicated.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| Accretion of asset retirement obligations | $6,082 | $6,158 | $7,302 |
| Legal proceeding settlement | 6,500 | — | — |
| Gain on debt extinguishment, net | — | (4,576) | — |
| Other, net | 4,582 | 5,757 | 18,824 |
| | $17,164 | $7,339 | $26,126 |

Accretion of Asset Retirement Obligations

Accretion of asset retirement obligations is the expense recognized to increase the carrying amount of the liability associated with our asset retirement obligations as a result of the passage of time. See Note 1 to the Consolidated Financial Statements for more information on our asset retirement obligations.

Legal Proceeding Settlement

During the second quarter of 2011, we settled litigation relating to the 2007 sale of our Alaska assets to Pacific Energy Resources, Ltd. ("PERL"), which included claims in excess of $250 million. PERL and the other plaintiffs released us from all claims and agreed to dismiss the complaint against us in exchange for a $7 million payment from us.

Gain on Debt Extinguishment

The net gain on debt extinguishment for the year ended December 31, 2010 includes the net gain related to the January 2010 redemption of our $150 million 7¾% senior notes due 2014 at 101.292% of par. A net gain was recognized due to the write-off, at the time the notes were redeemed, of unamortized deferred gains resulting from the previous termination of interest rate swaps related to these notes. This gain was partially offset by the $2 million redemption premium paid to redeem the notes. See Note 3 to the Consolidated Financial Statements for more information on our debt.

Income Tax

The table below sets forth the total income tax and effective income tax rates related to continuing operations for the periods indicated.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands, Except Percentages) | | |
| Current income tax | $30,141 | $(13,901) | $70,815 |
| Deferred income tax | 58,994 | 123,671 | (537,416) |
| Total income tax | $89,135 | $109,770 | $(466,601) |
| Effective income tax rate | 48% | 37% | 37% |

Our effective income tax rate generally approximates 37% to 38%. Our effective income tax rate was 48%, 37%, and 37% for the years ended December 31, 2011, 2010, and 2009, respectively. Our effective income tax rate was 48% for the year ended December 31, 2011 due to the Canadian dividend tax of $29 million that was incurred on a stock dividend declared and paid by our former Canadian subsidiary, Lone Pine Resources Canada Ltd. (“LPR Canada”), to Forest, as parent, immediately before Forest’s contribution of LPR Canada to Lone Pine in conjunction with Lone Pine’s initial public offering. Without the $29 million dividend tax, our effective income tax rate would have been 38% in 2011. See Note 4 to the Consolidated Financial Statements for a reconciliation of income tax computed by applying the United States federal statutory income tax rates for each period presented.

Discontinued Operations

The results of operations of Lone Pine are presented as discontinued operations in our Consolidated Statements of

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Operations due to the spin-off of Lone Pine on September 30, 2011, with prior periods' results recast to conform with the discontinued operations presentation. Earnings from discontinued operations was negatively impacted by a ceiling test write-down in the Canadian cost center of $199 million during 2009. See Note 13 to the Consolidated Financial Statements for more information regarding the components of discontinued operations.

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 operations and our bank credit facility as our primary sources of liquidity. To fund large transactions, such as acquisitions and debt refinancing transactions, we have looked to the private and public capital markets as another source of financing and, as market conditions have permitted, we have engaged in asset monetization transactions.

Changes in the market prices for oil, natural gas, and NGLs directly impact our level of cash flow generated from operations. Natural gas accounted for approximately 72% of our total production in 2011 and, as a result, our operations and cash flow are more sensitive to fluctuations in the market price for natural gas than to fluctuations in the market price for oil and NGLs. We employ a commodity hedging strategy as an attempt to moderate the effects of wide fluctuations in commodity prices on our cash flow. As of February 16, 2012, we had hedged, via commodity swaps, approximately 67 Bcfe of our total projected 2012 production and approximately 29 Bcf of our total projected 2013 production, excluding outstanding commodity swaptions and put options. 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. However, these hedging activities may result in reduced income or even financial losses to us. See Part I, Item 1A,—"Risk Factors—Our use of hedging transactions could reduce our cash flow and/or result in reported losses," for further details of the risks associated with our hedging activities. In the future, we may determine to increase or decrease our hedging positions. As of February 16, 2012, all of our derivative instrument counterparties are lenders, or affiliates of lenders, under our credit facility, with the exception of one counterparty. See Part II, Item 7A—"Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk," below for more information on our derivative contracts including commodity swaptions and put options.

The other primary source of liquidity is our credit facility, which had a borrowing base of $1.25 billion as of December 31, 2011. This facility is used to fund daily operations and to fund acquisitions and refinance debt, as needed and if available. The credit facility is secured by a portion of our assets, with the facility maturing in June 2016. See—"Bank Credit Facility" below for further details. We had $105 million and $140 million drawn on our credit facility as of December 31, 2011 and January 31, 2012, respectively.

The public and private capital markets have served as our primary source of financing to fund large acquisitions and other exceptional transactions. In the past, we have issued debt and equity in both the public and private capital markets. For example, in February 2009, we issued $600 million principal amount of 8½% senior notes due 2014 in a private offering for net proceeds of $560 million, and in May 2009, we issued approximately 14 million shares of common stock for net proceeds of $256 million. Our ability to access the debt and equity capital markets on economic terms is affected by general economic conditions, the domestic and global financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of our equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control.

We also have engaged in asset dispositions as a means of generating additional cash to fund expenditures and enhance our financial flexibility. For example, during 2011, 2010, and 2009, we sold certain assets for approximately $121 million, $139 million, and $933 million, respectively, with a portion of these proceeds used to pay off the outstanding balance under our credit facility in 2009 and redeem our 7¾% senior notes due 2014 in January 2010.

We believe that our cash flows provided by operating activities and the funds available under our 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 flow 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 financial flexibility to adjust our spending levels will provide us with sufficient liquidity to meet our financial obligations. See Part I, Item 1A—"Risk

Factors," for a discussion of the risks and uncertainties that affect our business and financial and operating results.
Bank Credit Facility
On June 30, 2011, we entered into the Third Amended and Restated Credit Agreement (the "Credit Facility") with a syndicate of banks led by JPMorgan Chase Bank, N.A., consisting of a $1.5 billion credit facility maturing in June 2016.

Subject to the agreement of us and the applicable lenders, the size of the Credit Facility may be increased by $300 million, to a total of $1.8 billion.

Our availability under the Credit Facility is governed by a borrowing base. As of December 31, 2011, the borrowing base under the Credit Facility was $1.25 billion. The determination of the borrowing base is made by the lenders in their sole discretion, on a semi-annual basis, taking into consideration the estimated value of our oil and gas properties based on pricing models determined by the lenders at such time, in accordance with the lenders' customary practices for oil and gas loans. The available borrowing amount under the Credit Facility could increase or decrease based on such redetermination. 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 a calendar year, to have the borrowing base redetermined. The borrowing base is also subject to automatic adjustments if certain events occur. The borrowing base was reaffirmed at $1.25 billion in October 2011 and the next scheduled redetermination of the borrowing base will occur on or about May 1, 2012.

The borrowing base is also subject to change in the event (i) we or our 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 notes, excluding any senior unsecured notes that we or any of our Restricted Subsidiaries may issue to refinance then-existing senior notes, or (ii) we sell 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. If the borrowing base is reduced to a level that is below our level of borrowing under the Credit Facility, we would be required to repay indebtedness in excess of the borrowing base in order to cover the deficiency.

Borrowings under the Credit Facility bear interest at one of two rates as may be elected by us. Borrowings bear interest at:

(i) the greatest of (a) the prime rate announced by JPMorgan Chase Bank, N.A., (b) the federal funds effective rate from time to time plus ½ of 1%, and (c) the one-month rate applicable to dollar deposits in the London interbank market for one, two, three or six months (as selected by us) (the "LIBO Rate") plus 1%, plus, in the case of each of clauses (a), (b), and (c), 50 to 150 basis points depending on borrowing base utilization; or

(ii) the LIBO Rate as adjusted for statutory reserve requirements (the "Adjusted LIBO Rate"), plus 150 to 250 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, mergers, and acquisitions, and also includes a financial covenant. The 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 twelve-month period to be greater than 4.50 to 1.00 at any time.

Under certain conditions, amounts outstanding under the Credit Facility may be accelerated. Bankruptcy and insolvency events with respect to us or certain of our 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 Credit 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 our assets. Under the Credit Facility, we are required to mortgage and grant a security interest in 75% of the present value of our and our U.S. subsidiaries' estimated proved oil and gas properties and related assets. We are required to pledge, and have pledged, the stock of certain subsidiaries to secure the Credit Facility. If our corporate credit rating by Moody's and S&P meet pre-established levels, the security requirements would cease to apply and, at our request, the banks would release their liens and security interest on our properties.

Of the $1.5 billion total nominal amount under the Credit Facility, JPMorgan and eleven other banks hold approximately 68% of the total commitments, with each of these twelve lenders holding an equal share. With respect to the other 32% of the total commitments, no single lender holds more than 3.3% of the total commitments.

Commitment fees accrue on the amount of unutilized borrowing base. If borrowing base utilization is greater than 50%, commitment fees are 50 basis points of the unutilized amount, and if borrowing base utilization is 50% or less, commitment fees are 35 basis points of the unutilized amount.

Prior to entering into the Credit Facility, the previous combined credit facility, the Second Amended and Restated Credit Agreement dated as of June 6, 2007, consisting of U.S. and Canadian facilities (the “Combined Credit Facility”) was amended on May 25, 2011, to, among other things, remove any collateral owned by Lone Pine or any of its subsidiaries from the collateral securing the U.S. portion of the Combined Credit Facility, terminate the previous Canadian portion of the Combined Credit Facility, terminate various guaranties securing the Canadian portion of the Combined Credit Facility, release collateral

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securing the Canadian portion of the Combined Credit Facility, and terminate certain liens and mortgages securing the Canadian portion of the Combined Credit Facility.

At December 31, 2011, there were outstanding borrowings of $105 million under the Credit Facility at a weighted average interest rate of 2.1% and we had used the Credit Facility for $2 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of $1.1 billion. At January 31, 2012, there were outstanding borrowings of $140 million under the Credit Facility at a weighted average interest rate of 1.8% and we had used the Credit Facility for $2 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of $1.1 billion.

Credit Ratings

Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate each series of our senior notes and, in addition, they have assigned Forest a general credit rating. Our Credit Facility includes provisions that are linked to our credit ratings. For example, our collateral requirements will vary based on our credit ratings; however, we do not have any credit rating triggers that would accelerate the maturity of amounts due under the Credit Facility or the debt issued under the indentures for our senior notes. The indentures for our senior notes also include terms linked to our credit ratings. These terms allow us greater flexibility if our credit ratings improve to investment grade and other tests have been satisfied, in which event we would not be obligated to comply with certain restrictive covenants included in the indentures. Our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Historical Cash Flow

Net cash provided by operating activities of continuing operations, net cash (used) provided by investing activities of continuing operations, and net cash used by financing activities of continuing operations 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 of continuing operations | $398,097 | $446,725 | $536,374 |
| Net cash (used) provided by investing activities of continuing operations | (759,730) | (423,054) | 356,889 |
| Net cash used by financing activities of continuing operations | (173,305) | (142,211) | (401,199) |

Net cash provided by operating activities of continuing operations is generally primarily affected by sales volumes and commodity prices net of the effects of settlements of our derivative contracts and changes in working capital. The decrease in net cash provided by operating activities of continuing operations of $49 million in 2011 as compared to 2010 was primarily due to (i) lower sales volumes that was offset by higher prices that resulted in little change in revenues; (ii) lower realized gains on commodity derivative instruments of $62 million; and, (iii) an increase in current income tax expense of $44 million. These decreases were partially offset by a decreased investment in net operating assets (i.e., working capital) of $69 million. The decrease in net cash provided by operating activities of continuing operations of $90 million in 2010 as compared to 2009 was primarily due to (i) lower realized gains on commodity derivative instruments of $197 million and (ii) an increased investment in net operating assets (i.e., working capital) of $80 million. These decreases were partially offset by (i) a decrease in current income tax expense of $85 million; (ii) increased revenue of $52 million due to increased commodity prices offsetting decreased sales volumes; and, (iii) decreased production expense of $23 million.

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The components of net cash (used) provided by investing activities of continuing operations for the years ended December 31, 2011, 2010, and 2009 were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| Exploration, development, acquisition, and leasehold costs[1] | $(873,877) | $(556,988) | $(545,357) |
| Proceeds from sales of assets | 121,115 | 139,077 | 933,492 |
| Other fixed asset costs | (6,968) | (5,143) | (31,274) |
| Other, net | — | — | 28 |
| Net cash (used) provided by investing activities of continuing operations | $(759,730) | $(423,054) | $356,889 |

(1) Cash paid for exploration, development, and acquisition costs as reflected in the Consolidated Statements of Cash Flows differs from the reported capital expenditures in the "Capital Expenditures" table below due to the timing of when the capital expenditures are incurred and when the actual cash payment is made as well as non-cash capital expenditures such as capitalized stock-based compensation costs.

Net cash (used) provided by investing activities of continuing operations is primarily comprised of expenditures for the acquisition, exploration, and development of oil and gas properties net of proceeds from the dispositions of oil and gas properties and other capital assets. The $337 million increase in cash used for investing activities of continuing operations between 2011 and 2010 was primarily due to an increase in leasehold acquisition costs in 2011 as well as capital expenditures incurred in 2011 associated with our Eagle Ford Shale and Wolfcamp development where non-recurring activities such as core sampling, acquiring 3-D seismic, and drilling micro-seismic wells were performed. The $780 million fluctuation in investing cash flows of continuing operations between 2010 and 2009 was primarily due to a $794 million decrease in proceeds from the sales of oil and gas properties due to the completion of the majority of our property divestiture program in 2009.

Net cash used by financing activities of continuing operations of $173 million in 2011 primarily included the redemption of the 8% senior notes in December 2011 for $285 million, partially offset by net credit facility borrowings of $105 million. Net cash used by financing activities of continuing operations of $142 million in 2010 primarily included the redemption of the 7¾% senior notes for $152 million. Net cash used by financing activities of continuing operations of $401 million in 2009 primarily included net repayments of bank borrowings of $1.2 billion, partially offset by net proceeds of $560 million for the issuance of 8½% senior notes due 2014 and net proceeds of $256 million for the issuance of common stock.

Capital Expenditures

Expenditures from continuing operations for property exploration, development, and acquisitions were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| Property Acquisitions: | | | |
| Proved properties | $— | $5,823 | $— |
| Unproved properties including leasehold acquisition costs | 204,537 | 64,593 | 45,230 |
| | 204,537 | 70,416 | 45,230 |
| Exploration: | | | |
| Direct costs | 272,422 | 172,746 | 106,586 |
| Overhead capitalized | 20,964 | 22,241 | 15,689 |
| | 293,386 | 194,987 | 122,275 |
| Development: | | | |
| Direct costs | 392,406 | 299,461 | 314,504 |
| Overhead capitalized | 25,429 | 20,366 | 25,841 |
| | 417,835 | 319,827 | 340,345 |

| | | | |
|---|---|---|---|
| Total capital expenditures[1] | $915,758 | $585,230 | $507,850 |

(1) Total capital expenditures include cash expenditures, accrued expenditures, and non-cash capital expenditures including stock-based compensation capitalized under the full cost method of accounting. Total capital expenditures also include changes in estimated discounted asset retirement obligations of $3 million, $(1) million, and $1 million recorded during the years ended December 31, 2011, 2010, and 2009, respectively.

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We have established an exploration and development capital budget of $480 million to $520 million for 2012 and plan to focus heavily on oil and other liquids-based drilling opportunities within our concentrated asset base. Primary factors impacting the level of our capital expenditures include crude oil and natural gas prices, the volatility in these prices, the cost and availability of oil field services, general economic and market conditions, and weather disruptions.

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 debt(1) | $6,230 | $6,230 | $6,230 | $6,230 | $108,115 | $— | $133,035 |
| Senior notes(2) | 123,501 | 123,512 | 678,875 | 72,500 | 72,500 | 1,178,229 | 2,249,117 |
| Derivative liabilities(3) | 28,944 | — | — | — | — | — | 28,944 |
| Other liabilities(4) | 6,114 | 11,868 | 9,842 | 9,478 | 14,124 | 72,763 | 124,189 |
| Operating leases(5) | 29,728 | 29,010 | 24,038 | 17,263 | 16,917 | 19,836 | 136,792 |
| Unconditional purchase obligations(6) | 4,333 | 851 | — | — | — | — | 5,184 |
| Total contractual obligations | $198,850 | $171,471 | $718,985 | $105,471 | $211,656 | $1,270,828 | $2,677,261 |

(1) Bank debt consists of the $105 million outstanding balance under our credit facility as of December 31, 2011 and the anticipated interest payments on that balance, as well as commitment and letter of credit fees based on the $1.25 billion borrowing base and $2 million in outstanding letters of credit as of December 31, 2011, assuming all such balances remain until the maturity of the credit facility.

(2) Senior notes consist of the principal obligations on our senior notes and senior subordinated notes and anticipated interest payments due on each.

(3) Derivative liabilities represent the fair value of our derivative liabilities as of December 31, 2011. The ultimate settlement amounts of our derivative liabilities are unknown, because they are subject to continuing market risk. See "Critical Accounting Policies, Estimates, Judgments, and Assumptions" below for a more detailed discussion of the nature of the accounting estimates involved in valuing derivative instruments.

(4) Other liabilities are comprised of pension and other postretirement benefit obligations and asset retirement obligations, for which neither the ultimate settlement amounts nor their timings 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.

(5) Operating leases consist of leases for drilling rigs, compressors, and office facilities and equipment.

(6) Unconditional purchase obligations consist primarily of drilling commitments, throughput obligations, and seismic purchase obligations.

We also make delay rental payments to lessors during the primary terms of oil and gas leases to delay drilling or production of wells, usually for one year. Although we are not obligated to make such payments, discontinuing them would result in the loss of the oil and gas lease. Our maximum commitment of future delay lease rental payments, through 2019, totaled approximately $11 million as of December 31, 2011.

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 (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, and (iv) 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 derivative contracts, pension and other postretirement benefit obligations, and asset retirement 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.

Surety Bonds

In the ordinary course of our business and operations, we are required to post surety bonds from time to time with third parties, including governmental agencies. As of February 16, 2012, we had obtained surety bonds from a number of insurance and bonding institutions covering certain of our current and former operations in the United States in the aggregate amount of approximately $15 million. See Part I, Item 1—"Business—Industry Regulation" for further information.

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## Critical Accounting Policies, Estimates, Judgments, and Assumptions

### 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.

Under the full cost method, separate cost centers are maintained for each country in which we incur costs. All costs incurred in the acquisition, exploration, and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) are capitalized. The fair value of estimated future costs of site restoration, dismantlement, and abandonment activities is capitalized, and a corresponding asset retirement obligation liability is recorded.

Capitalized costs applicable to each 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. Changes in estimates of reserves or future development costs are accounted for in the current quarter and prospectively in the depletion calculations. We have historically updated our quarterly depletion calculations with our quarter-end reserves estimates. Based on this accounting policy, our December 31, 2011 reserves estimates were used for our fourth quarter 2011 depletion calculation. See Part I, Item 1, "Business—Reserves" and Note 15 to the Consolidated Financial Statements for a more complete discussion of our estimated proved reserves as of December 31, 2011.

Companies that use the full cost method of accounting for oil and 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 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 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. Forest recorded a $1.4 billion non-cash ceiling test write-down in the first quarter of 2009 as a result of significant declines in oil and natural gas prices at that time. We have not incurred a ceiling test write-down since March 31, 2009 through December 31, 2011. Our ceiling test calculations are based on the twelve-month average natural gas and oil prices since December 31, 2009 in accordance with SEC regulations.

In countries or 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 depreciation, depletion, and amortization, 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 appropriate full cost pool, or reported as impairment expense in the Consolidated Statements of Operations, as applicable.

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 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 tested for impairment on an annual basis in the second quarter of the year. 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 our reporting unit, which we have

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determined to be our U.S. geographic operating segment, and compare the fair value with the carrying value of the net assets assigned to the reporting unit. If the fair value of a reporting unit is greater than the carrying value of the net assets assigned to 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 a 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 was 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 our 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 Forest's weighted average cost of capital.

We did not record an impairment charge as a result of our goodwill impairment test in the second quarter of 2011 and no events or circumstances have occurred since then that have indicated a possible impairment, requiring an updated test. 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 Reserves Estimates

Our estimates of proved reserves are based on the quantities of oil and 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 governmental regulations, prior to the time at which contracts providing the right to operate expire. The accuracy of any reserves 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 gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and 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 gas disclosures included in Note 15 to the Consolidated Financial Statements.

Reference should be made to "Reserves" under Part I, Item 1—"Business," and "Our estimates of oil and natural gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves and our financial condition," under Part I, Item 1A—"Risk Factors," in this Annual Report on Form 10-K.

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 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 "Realized and unrealized gains or losses on derivative instruments, net" 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 Item 7A—"Quantitative and Qualitative Disclosures about Market

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Risk" for a sensitivity analysis of the change in net fair values of our commodity and interest rate derivatives based on a hypothetical change in commodity prices and interest rates.

Valuation of Deferred Tax Assets

We use the asset and liability method of accounting for income taxes. Under this method, income tax assets and liabilities are determined based on differences between the financial statement carrying values of assets and liabilities and their respective income tax bases (temporary differences). Income tax assets and liabilities are measured using the tax rates expected to be in effect when the temporary differences are likely to reverse. The effect on income tax assets and liabilities of a change in tax rates is included in earnings in the period in which the change is enacted. The book value of income tax assets is limited to the amount of the tax benefit that is more likely than not to be realized in the future.

In assessing the need for a valuation allowance on our deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon whether future book income is sufficient to reverse existing temporary differences that give rise to deferred tax assets, as well as whether future taxable income is sufficient to utilize net operating loss and credit carryforwards. Assessing the need for, or the sufficiency of, a valuation allowance requires the evaluation of all available evidence, both negative and positive.

Negative evidence considered by management primarily included book losses incurred in 2008 and 2009 that were driven entirely from ceiling test write-downs, which are not fair value based measurements. Under the full cost method of accounting, we recorded $3.7 billion in ceiling test write-downs of the book value of our U.S. oil and gas properties in 2008 and 2009, which substantially reduced the book value of our oil and gas properties, resulting in the recognition of a net deferred tax asset. However, the write-downs also substantially reduced our prospective depletion rate at the time the write-downs occurred, making future book income, and therefore the reversal of book to tax temporary differences, more likely than would be the case had these ceiling test write-downs not occurred. Positive evidence considered by management included book income in 2010 and 2011, forecasted book income over a reasonable period of time, and the utilization of substantially all of our then existing net operating loss ("NOL") carryforwards in 2009 due primarily to a substantial tax gain associated with the sale of nearly $1 billion in U.S. oil and gas assets. Based upon the evaluation of what management determined to be relevant evidence, we have not recorded a valuation allowance against our U.S. deferred tax assets as of December 31, 2011. See Note 4 to the Consolidated Financial Statements. The primary evidence utilized to determine that it is more likely than not that our deferred tax assets will be realized was management's expectation of future book income over the next several years, the expectation that we will utilize our net operating losses as of December 31, 2011 by carrying them back to 2009, and the fact that AMT credit carryforwards do not expire.

Asset Retirement Obligations

Forest has obligations to remove tangible equipment and restore locations at the end of the oil and gas production operations. Estimating the future restoration and removal costs, or asset retirement obligations, 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 periodically change, as do regulatory, political, environmental, safety, and public relations considerations. Inherent in the calculation of the present value of our asset retirement obligations ("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 gas property balance. Increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, which is included in "Other, net" in the Consolidated Statements of Operations.

Impact of Recently Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2011-05, Comprehensive Income, Presentation of Comprehensive Income (“ASU 2011-05”), which provides amendments that will result in more converged guidance on how comprehensive income is presented under U.S. generally accepted accounting principles (“U.S. GAAP”) and International Financial Reporting Standards (“IFRS”). ASU 2011-05 requires an entity 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 eliminates the option to report other comprehensive income and its components in the statement of shareholders' equity. ASU 2011-05 also requires entities 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. 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

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Other Comprehensive Income in Accounting Standards Update No. 2011-05 (“ASU 2011-12”), which indefinitely defers the requirements in 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. Both ASU 2011-05 and ASU 2011-12 are effective for interim and annual periods beginning after December 15, 2011, and should be applied retrospectively. The adoption of this authoritative guidance will not have an impact on our financial position or results of operations, but will require us to present the statements of comprehensive income separately from our statements of shareholders' equity, as these statements are currently presented on a combined basis.

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 U.S. GAAP fair value measurement and disclosure guidance, to converge U.S. 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 fair value measurements and disclosures.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment (“ASU 2011-08”), 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 U.S. GAAP and IFRS financial statements by requiring enhanced disclosures, but does not change existing U.S. 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. The adoption of this authoritative guidance will not have an impact on our financial position or results of operations, but will require us to make enhanced disclosures regarding our derivative instruments.

Reconciliation of Non-GAAP Measure

Adjusted EBITDA

In addition to reporting net earnings from continuing operations as defined under GAAP, we also present adjusted earnings from continuing operations before interest, income taxes, depreciation, depletion, and amortization (“Adjusted EBITDA”), which is a non-GAAP performance measure. Adjusted EBITDA consists of net earnings from continuing operations before interest expense, income taxes, depreciation, depletion, and amortization, as well as other non-cash operating items such as unrealized gains and losses on derivative instruments and accretion of asset retirement obligations and other items presented in the table below. Adjusted EBITDA does not represent, and should not be considered an alternative to, GAAP measurements, such as net earnings from continuing operations (its most comparable GAAP financial measure), and our calculations thereof may not be comparable to similarly titled measures reported by other companies. By eliminating interest, taxes, depreciation, depletion, amortization, and other items from earnings, we believe the result is a useful measure across time in evaluating our fundamental core operating performance. Management also uses Adjusted EBITDA to manage its business, including in preparing its 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. Our management does not view Adjusted EBITDA in isolation and also uses other measurements, such as net earnings from continuing operations and revenues to measure operating performance. The following table provides a reconciliation of net earnings from continuing operations, the most directly comparable GAAP measure, to Adjusted EBITDA for the periods presented.

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| | Year Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | (In Thousands) | | |
| Net earnings (loss) from continuing operations | $98,260 | $189,662 | $(793,789) |
| Income tax expense (benefit) | 89,135 | 109,770 | (466,601) |
| Unrealized (gains) losses on derivative instruments, net | (39,087) | (37,920) | 176,018 |
| Unrealized losses on other investments | — | — | 2,327 |
| Interest expense | 149,755 | 149,891 | 161,083 |
| Legal proceeding settlement | 6,500 | — | — |
| Gain on debt extinguishment, net | — | (4,576) | — |
| Accretion of asset retirement obligations | 6,082 | 6,158 | 7,302 |
| Ceiling test write-down of oil and gas properties | — | — | 1,376,822 |
| Depreciation, depletion, and amortization | 219,684 | 187,973 | 247,158 |
| Stock-based compensation | 20,536 | 18,143 | 16,209 |
| Adjusted EBITDA from continuing operations | $550,865 | $619,101 | $726,529 |

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 in the United States. As a result, our financial results are affected when prices for these commodities fluctuate. Such effects can be significant. In order to reduce the impact of fluctuations in commodity prices, or to protect the economics of property acquisitions, we make use of a commodity hedging strategy. Under our hedging strategy, we enter into commodity swaps, collars, and other derivative instruments with counterparties who, in general, are lenders, or affiliates of such lenders, in our credit facility. These arrangements, which are typically 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.

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:

| | Commodity Swaps | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Natural Gas (NYMEX HH) | | | Oil (NYMEX WTI) | | | NGLs (OPIS Refined Products) | | |
| Swap Term | Bbtu Per Day | Weighted Average Hedged Price per MMBtu | Fair Value (In Thousands) | Barrels Per Day | Hedged Price per Bbl | Fair Value (In Thousands) | Barrels Per Day | Weighted Average Hedged Price per Bbl | Fair Value (In Thousands) |
| Calendar 2012[(1)] | 105 | $5.30 | $78,145 | — | $— | $— | 2,000 | $45.22 | $(5,396) |
| January 2012 - June 2012 | — | — | — | 5,000 | 98.24 | (901) | — | — | — |
| July 2012 - December | — | — | — | 4,500 | 97.26 | (910) | — | — | — |

2012

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(1) During the fourth quarter, we entered into derivative agreements for the period April 2012 - December 2012 subjecting 50 Bbtu per day of the 2012 gas swaps to a written put of $3.53 and a $4.00 to $4.50 call spread whereby we receive $5.30 except as follows: we receive (i) NYMEX HH plus $1.77 when NYMEX HH is below $3.53; (ii) $5.30 plus the value of the call spread when NYMEX HH is between $4.00 and $4.50; and (iii) $5.80 when NYMEX HH is $4.50 or above. The fair value of these derivative agreements as of December 31, 2011 was a liability of $5.8 million.

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Commodity Options

In connection with several natural gas swaps entered into, we granted option instruments to the natural gas swap counterparties in exchange for Forest receiving premium hedged prices on the natural gas swaps. The table below sets forth the outstanding options as of December 31, 2011 (as of February 16, 2012, none of the swaptions in the table have been exercised by the counterparties).

| | Commodity Options | | | | |
|---|---|---|---|---|---|
| | | | Oil (NYMEX WTI) | | |
| Instrument | Option Expiration | Underlying Swap Term | Underlying Swap Barrels Per Day | Underlying Swap Hedged Price per Bbl | Fair Value (In Thousands) |
| Oil Swaptions | June 2012 | July - December 2012 | 500 | $107.10 | $(498) |
| Oil Swaptions | December 2012 | Calendar 2013 | 5,000 | 105.00 | (14,098) |

The estimated fair value of all our commodity derivative instruments based on various inputs, including published forward prices, at December 31, 2011 was a net asset of approximately $51 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 decrease the net fair value of our commodity derivative instruments at December 31, 2011 by approximately $39 million to a net asset of $12 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.

Derivative Instruments Entered Into Subsequent to December 31, 2011

Subsequent to December 31, 2011, through February 16, 2012, we entered into the following derivative agreements:

| | Commodity Swaps | |
|---|---|---|
| | Natural Gas (NYMEX HH) | |
| Swap Term | Bbtu Per Day | Weighted Average Hedged Price per MMBtu |
| April 2012 - December 2012[(1)] | 50 | $3.23 |
| Calendar 2013[(2)] | 80 | 4.02 |

(1) In connection with entering into these natural gas swaps with premium hedged prices, we granted oil puts to the counterparties, giving the counterparties the option to put 5,000 barrels per day to us at $75.00 per barrel on a monthly basis during April 2012 - December 2012.

(2) In connection with entering into these natural gas swaps with premium hedged prices, we granted some of the counterparties with the option to enter into oil swaps with us for Calendar 2014 covering 3,000 barrels per day at a weighted average hedged price per barrel of $109.67, with such options expiring in December 2013, and granted the other counterparties with the option to enter into natural gas swaps with us for Calendar 2013 covering 20 Bbtu per day at a weighted average hedged price per MMBtu of $4.02, with such options expiring in December 2012.

Interest Rate Risk

We periodically enter into interest rate derivative agreements in an attempt to manage the mix of fixed and floating interest rates within our debt portfolio. As of December 31, 2011, we had entered into the following fixed-to-floating interest rate swaps:

| | Interest Rate Swaps | | | |
|---|---|---|---|---|
| Remaining Swap Term | Notional Amount | Weighted Average | Weighted Average | Fair Value |

| | (In Thousands) | Floating Rate | Fixed Rate | | (In Thousands) |
|---|---|---|---|---|---|
| January 2012 - February 2014 | $500,000 | 1 month LIBOR + 5.89% | 8.50 | % | $20,556 |

The estimated fair value of all our interest rate derivative instruments based on various inputs, including published forward rates, at December 31, 2011 was an asset of approximately $21 million.

Due to the volatility of interest rates, the estimated fair values of our interest rate derivative instruments are subject to

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fluctuations from period to period. For example, a hypothetical 10% increase in the forward 1-month LIBOR interest rates used to calculate the fair values of our interest rate derivative instruments at December 31, 2011 would decrease the net fair value of our interest rate derivative instruments at December 31, 2011 by approximately $1 million to an asset of $20 million. Actual gains or losses recognized related to our interest rate derivative instruments will likely differ from those estimated at December 31, 2011 and will depend exclusively on the future 1-month LIBOR interest rates.

Derivative Fair Value Reconciliation

The table below sets forth the changes that occurred in the fair values of our derivative contracts during the year ended December 31, 2011, beginning with the fair value of our derivative contracts on December 31, 2010. It has been our experience that commodity prices are subject to large fluctuations, and we expect this volatility to continue. 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. Actual gains and 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.

| | Fair Value of Derivative Contracts | | |
|---|---|---|---|
| | Commodity | Interest Rate | Total |
| | (In Thousands) | | |
| As of December 31, 2010 | $13,002 | $19,011 | $32,013 |
| Net increase in fair value | 75,076 | 12,987 | 88,063 |
| Net contract gains recognized | (37,535) | (11,442) | (48,977) |
| As of December 31, 2011 | $50,543 | $20,556 | $71,099 |

Interest Rates on Borrowings

The following table presents principal amounts and related interest rates by year of maturity for Forest's debt obligations at December 31, 2011:

| | 2013 | 2014 | 2016 | 2019 | Total |
|---|---|---|---|---|---|
| | (Dollar Amounts in Thousands) | | | | |
| Bank credit facility: | | | | | |
| Variable rate | $— | $— | $105,000 | $— | $105,000 |
| Average interest rate[(1)] | — | — | 2.09% | — | 2.09% |
| Senior notes: | | | | | |
| Principal | $12 | $600,000 | $— | $1,000,000 | $1,600,012 |
| Fixed interest rate | 7.00% | 8.50% | — | 7.25% | 7.72% |
| Effective interest rate[(2)] | 7.49% | 9.47% | — | 7.24% | 8.08% |

(1) As of December 31, 2011.

(2) The effective interest rates on the senior notes differ from the fixed interest rates due to the amortization of related discounts or premiums on the notes.

Foreign Currency Exchange Rate Risk

We conduct business in Italy and South Africa, and thus are subject to foreign currency exchange rate risk on cash flows related primarily to expenses and investing transactions. We have not entered into any foreign currency forward contracts or other similar financial instruments to manage this risk. Expenditures incurred relative to the foreign concessions held by Forest outside of North America have been primarily United States dollar-denominated.

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Item 8. Financial Statements and Supplementary Data.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Forest Oil Corporation

We have audited the accompanying consolidated balance sheets of Forest Oil Corporation and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Forest Oil Corporation and subsidiaries at December 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Forest Oil Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Denver, Colorado
February 21, 2012

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FOREST OIL CORPORATION
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Amounts)

| | December 31, 2011 | 2010 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $3,012 | $217,569 |
| Accounts receivable | 79,089 | 102,325 |
| Derivative instruments | 89,621 | 60,182 |
| Other current assets | 38,950 | 51,465 |
| Current assets of discontinued operations | — | 50,142 |
| Total current assets | 210,672 | 481,683 |
| Property and equipment, at cost: | | |
| Oil and gas properties, full cost method of accounting: | | |
| Proved, net of accumulated depletion of $6,901,997 and $6,688,012 | 1,923,145 | 1,370,864 |
| Unproved | 675,995 | 646,264 |
| Net oil and gas properties | 2,599,140 | 2,017,128 |
| Other property and equipment, net of accumulated depreciation and amortization of $47,989 and $42,432 | 51,976 | 53,145 |
| Net property and equipment | 2,651,116 | 2,070,273 |
| Deferred income taxes | 231,116 | 284,021 |
| Goodwill | 239,420 | 239,420 |
| Derivative instruments | 10,422 | 8,244 |
| Other assets | 38,405 | 36,698 |
| Long-term assets of discontinued operations | — | 665,049 |
| | $3,381,151 | $3,785,388 |
| LIABILITIES AND SHAREHOLDERS' EQUITY | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | $247,880 | $209,998 |
| Accrued interest | 23,259 | 23,630 |
| Derivative instruments | 28,944 | 36,413 |
| Deferred income taxes | 20,172 | 6,911 |
| Current portion of long-term debt | — | 287,092 |
| Other current liabilities | 20,582 | 19,683 |
| Current liabilities of discontinued operations | — | 45,647 |
| Total current liabilities | 340,837 | 629,374 |
| Long-term debt | 1,693,044 | 1,582,280 |
| Asset retirement obligations | 77,898 | 73,011 |
| Other liabilities | 76,259 | 73,463 |
| Long-term liabilities of discontinued operations | — | 74,473 |
| Total liabilities | 2,188,038 | 2,432,601 |
| Commitments and contingencies (Note 10) | | |
| Shareholders' equity: | | |
| Preferred stock, none issued and outstanding | — | — |
| Common stock, 114,525,673 and 113,594,788 shares issued and outstanding | 11,454 | 11,359 |
| Capital surplus | 2,486,994 | 2,684,269 |
| Accumulated deficit | (1,287,063) | (1,424,905) |

| | | |
|---|---|---|
| Accumulated other comprehensive (loss) income | (18,272) | 82,064 |
| Total shareholders' equity | 1,193,113 | 1,352,787 |
| | $3,381,151 | $3,785,388 |

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, Except Per Share Amounts)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Revenues: | | | |
| Oil, natural gas, and NGL sales | $703,531 | $707,692 | $655,579 |
| Interest and other | 1,026 | 989 | 800 |
| Total revenues | 704,557 | 708,681 | 656,379 |
| Costs, expenses, and other: | | | |
| Lease operating expenses | 99,158 | 92,394 | 119,472 |
| Production and property taxes | 40,632 | 43,656 | 40,147 |
| Transportation and processing costs | 13,728 | 13,242 | 12,855 |
| General and administrative | 65,105 | 64,886 | 65,254 |
| Depreciation, depletion, and amortization | 219,684 | 187,973 | 247,158 |
| Ceiling test write-down of oil and gas properties | — | — | 1,376,822 |
| Interest expense | 149,755 | 149,891 | 161,083 |
| Realized and unrealized gains on derivative instruments, net | (88,064) | (150,132) | (132,148) |
| Other, net | 17,164 | 7,339 | 26,126 |
| Total costs, expenses, and other | 517,162 | 409,249 | 1,916,769 |
| Earnings (loss) from continuing operations before income taxes | 187,395 | 299,432 | (1,260,390) |
| Income tax | 89,135 | 109,770 | (466,601) |
| Net earnings (loss) from continuing operations | 98,260 | 189,662 | (793,789) |
| Net earnings (loss) from discontinued operations | 44,569 | 37,859 | (129,344) |
| Net earnings (loss) | 142,829 | 227,521 | (923,133) |
| Less: net earnings attributable to noncontrolling interest | 4,987 | — | — |
| Net earnings (loss) attributable to Forest Oil Corporation | $137,842 | $227,521 | $(923,133) |
| | | | |
| Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders: | | | |
| Earnings (loss) from continuing operations | $.86 | $1.68 | $(7.61) |
| Earnings (loss) from discontinued operations | .35 | .33 | (1.24) |
| Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders | $1.21 | $2.01 | $(8.85) |
| | | | |
| Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders: | | | |
| Earnings (loss) from continuing operations | $.85 | $1.67 | $(7.61) |
| Earnings (loss) from discontinued operations | .34 | .33 | (1.24) |
| Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders | $1.19 | $2.00 | $(8.85) |
| | | | |
| Amounts attributable to Forest Oil Corporation common shareholders: | | | |
| Net earnings (loss) from continuing operations | $98,260 | $189,662 | $(793,789) |
| Net earnings (loss) from discontinued operations | 39,582 | 37,859 | (129,344) |
| Net earnings (loss) | $137,842 | $227,521 | $(923,133) |

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In Thousands)

| | Common Stock | | Capital Surplus | Retained Earnings (Accumulated Deficit) | Accumulated Other Comprehensive Income (Loss) | Forest Oil Corporation Shareholders' Equity | Noncontrolling Interest | Total Shareholders' Equity |
|---|---|---|---|---|---|---|---|---|
| | Shares | Amount | | | | | | |
| Balances at January 1, 2009 | 97,040 | $9,704 | $2,354,903 | $(729,293) | $37,598 | $1,672,912 | $— | $1,672,912 |
| Common stock issued, net of offering costs | 14,375 | 1,438 | 254,779 | — | — | 256,217 | — | 256,217 |
| Exercise of stock options | 171 | 17 | 3,049 | — | — | 3,066 | — | 3,066 |
| Employee stock purchase plan | 123 | 12 | 1,499 | — | — | 1,511 | — | 1,511 |
| Restricted stock issued, net of cancellations | 657 | 66 | (66) | — | — | — | — | — |
| Amortization of stock-based compensation | — | — | 26,820 | — | — | 26,820 | — | 26,820 |
| Tax impact of employee stock option exercises | — | — | 12,253 | — | — | 12,253 | — | 12,253 |
| Other, net | (29) | (3) | (548) | — | — | (551) | — | (551) |
| Comprehensive loss: | | | | | | | | |
| Net loss | — | — | — | (923,133) | — | (923,133) | — | (923,133) |
| Decrease in unfunded postretirement benefits, net of tax | — | — | — | — | 2,152 | 2,152 | — | 2,152 |
| Foreign currency translation | — | — | — | — | 27,907 | 27,907 | — | 27,907 |
| Total comprehensive loss | | | | | | (893,074) | — | (893,074) |
| Balances at December 31, 2009 | 112,337 | 11,234 | 2,652,689 | (1,652,426) | 67,657 | 1,079,154 | — | 1,079,154 |
| Exercise of stock options | 458 | 46 | 8,653 | — | — | 8,699 | — | 8,699 |
| Employee stock purchase plan | 64 | 6 | 1,431 | — | — | 1,437 | — | 1,437 |
| | 889 | 88 | (88) | — | — | — | — | — |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Restricted stock issued, net of cancellations | | | | | | | | |
| Amortization of stock-based compensation | — | — | 28,440 | — | — | 28,440 | — | 28,440 |
| Other, net | (153) | (15) | (6,856) | — | — | (6,871) | — | (6,871) |
| Comprehensive earnings: | | | | | | | | |
| Net earnings | — | — | — | 227,521 | — | 227,521 | — | 227,521 |
| Increase in unfunded postretirement benefits, net of tax | — | — | — | — | (746) | (746) | — | (746) |
| Foreign currency translation | — | — | — | — | 15,153 | 15,153 | — | 15,153 |
| Total comprehensive earnings | | | | | | 241,928 | — | 241,928 |
| Balances at December 31, 2010 | 113,595 | 11,359 | 2,684,269 | (1,424,905) | 82,064 | 1,352,787 | — | 1,352,787 |

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (Continued)
(In Thousands)

| | Common Stock Shares | Common Stock Amount | Capital Surplus | Retained Earnings (Accumulated Deficit) | Accumulated Other Comprehensive Income (Loss) | Forest Oil Corporation Shareholders' Equity | Noncontrolling Interest | Total Shareholders' Equity |
|---|---|---|---|---|---|---|---|---|
| Balances at December 31, 2010 | 113,595 | 11,359 | 2,684,269 | (1,424,905) | 82,064 | 1,352,787 | — | 1,352,787 |
| Issuance of Lone Pine Resources Inc. common stock | — | — | 112,610 | — | (18,007) | 94,603 | 83,572 | 178,175 |
| Spin-off of Lone Pine Resources Inc. | — | — | (333,568) | — | (54,125) | (387,693) | (82,242) | (469,935) |
| Exercise of stock options | 192 | 19 | 2,363 | — | — | 2,382 | — | 2,382 |
| Employee stock purchase plan | 96 | 10 | 1,331 | — | — | 1,341 | — | 1,341 |
| Restricted stock issued, net of cancellations | 861 | 86 | (86) | — | — | — | — | — |
| Amortization of stock-based compensation | — | — | 35,449 | — | — | 35,449 | — | 35,449 |
| Tax impact of employee stock option exercises | — | — | (9,608) | — | — | (9,608) | — | (9,608) |
| Other, net | (218) | (20) | (5,766) | — | — | (5,786) | — | (5,786) |
| Comprehensive earnings: | | | | | | | | |
| Net earnings | — | — | — | 137,842 | — | 137,842 | 4,987 | 142,829 |
| Increase in unfunded postretirement benefits, net of tax | — | — | — | — | (6,669) | (6,669) | — | (6,669) |
| Foreign currency translation | — | — | — | — | (21,535) | (21,535) | (6,317) | (27,852) |
| Total comprehensive earnings | | | | | | 109,638 | (1,330) | 108,308 |
| Balances at December 31, 2011 | 114,526 | $11,454 | $2,486,994 | $(1,287,063) | $(18,272) | $1,193,113 | $— | $1,193,113 |

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Operating activities: | | | |
| Net earnings (loss) | $142,829 | $227,521 | $(923,133) |
| Less: net earnings (loss) from discontinued operations | 44,569 | 37,859 | (129,344) |
| Net earnings (loss) from continuing operations | 98,260 | 189,662 | (793,789) |
| Adjustments to reconcile net earnings (loss) from continuing operations to net cash provided by operating activities of continuing operations: | | | |
| Depreciation, depletion, and amortization | 219,684 | 187,973 | 247,158 |
| Deferred income tax | 58,994 | 123,671 | (537,416) |
| Unrealized (gains) losses on derivative instruments, net | (39,087) | (37,920) | 176,018 |
| Ceiling test write-down of oil and gas properties | — | — | 1,376,822 |
| Stock-based compensation expense | 20,536 | 18,143 | 16,209 |
| Accretion of asset retirement obligations | 6,082 | 6,158 | 7,302 |
| Other, net | 8,114 | 2,463 | 7,671 |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | 23,236 | 2,640 | 26,622 |
| Other current assets | 14,314 | 24,136 | 33,241 |
| Accounts payable and accrued liabilities | (6,470) | (62,435) | (36,820) |
| Accrued interest and other current liabilities | (5,566) | (7,766) | 13,356 |
| Net cash provided by operating activities of continuing operations | 398,097 | 446,725 | 536,374 |
| Investing activities: | | | |
| Capital expenditures for property and equipment: | | | |
| Exploration, development, acquisition, and leasehold costs | (873,877) | (556,988) | (545,357) |
| Other fixed assets costs | (6,968) | (5,143) | (31,274) |
| Proceeds from sales of assets | 121,115 | 139,077 | 933,492 |
| Other, net | — | — | 28 |
| Net cash (used) provided by investing activities of continuing operations | (759,730) | (423,054) | 356,889 |
| Financing activities: | | | |
| Proceeds from bank borrowings | 160,000 | — | 747,000 |
| Repayments of bank borrowings | (55,000) | — | (1,937,000) |
| Issuance of senior notes, net of issuance costs | — | — | 559,767 |
| Redemption of senior notes | (285,000) | (152,038) | (970) |
| Proceeds from common stock offering, net of offering costs | — | — | 256,217 |
| Proceeds from the exercise of options and from employee stock purchase plan | 3,723 | 10,136 | 4,577 |
| Payment of debt issue costs | (8,191) | — | (3,385) |
| Change in bank overdrafts | 17,116 | 6,378 | (38,943) |
| Other, net | (5,953) | (6,687) | 11,538 |
| Net cash used by financing activities of continuing operations | (173,305) | (142,211) | (401,199) |
| Cash flows of discontinued operations: | | | |
| Operating cash flows | 101,292 | 86,204 | 60,622 |
| Investing cash flows | (255,470) | (218,155) | 28,483 |

| | | | |
|---|---|---|---|
| Financing cash flows | 478,324 | 1,692 | (115,665) |
| Net cash provided (used) by discontinued operations | 324,146 | (130,259) | (26,560) |
| Effect of exchange rate changes on cash | (3,476) | (277) | (488) |
| Net (decrease) increase in cash and cash equivalents | (214,268) | (249,076) | 465,016 |
| Net (increase) decrease in cash and cash equivalents of discontinued operations | (289) | 8,370 | (8,946) |
| Net (decrease) increase in cash and cash equivalents of continuing operations | (214,557) | (240,706) | 456,070 |
| Cash and cash equivalents of continuing operations at beginning of year | 217,569 | 458,275 | 2,205 |
| Cash and cash equivalents of continuing operations at end of year | $3,012 | $217,569 | $458,275 |
| Cash paid by continuing operations during the year for: | | | |
| Interest (net of amounts capitalized) | $139,311 | $140,856 | $133,947 |
| Income taxes | 2,861 | 53,748 | 4,302 |
| Non-cash investing activities of continuing operations: | | | |
| Increase (decrease) in accrued capital expenditures | $27,235 | $16,405 | $(61,765) |
| Increase (decrease) in asset retirement costs | 3,109 | (1,081) | 1,114 |

See accompanying Notes to Consolidated Financial Statements.

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FOREST OIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2011, 2010, and 2009

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Description of the Business

Forest Oil Corporation is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids (“NGLs”) primarily in the United States. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Forest holds assets in several exploration and producing areas in the United States and has exploratory and development interests in two other countries. 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 subsidiary, Lone Pine Resources Inc. (“Lone Pine”), 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 common stock. On September 30, 2011, Forest completed the spin-off of the 70 million shares of Lone Pine held by Forest in the form of a pro rata common stock dividend to all Forest shareholders. See Note 5 for more information regarding the initial public offering and spin-off of Lone Pine. Unless the context indicates otherwise, the terms “Forest,” the “Company,” “we,” “our,” and “us,” as used in this Annual Report on Form 10-K, refer to Forest Oil Corporation and its subsidiaries.

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of Forest and its consolidated subsidiaries. The results of operations of Lone Pine are reported as discontinued operations due to the spin-off, with prior periods being recast for comparative purposes. All intercompany balances and transactions have been eliminated. Certain amounts in prior years' financial statements have been reclassified to conform to the 2011 financial statement presentation.

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, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts previously established.

The more significant areas requiring the use of assumptions, judgments, and estimates relate to volumes of oil and gas reserves used in calculating depletion, the amount of future net revenues used in computing the ceiling test limitations, 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.

Cash Equivalents

The Company considers all highly liquid investments with original maturities of three months or less and all money market funds with no restrictions on the Company's ability to withdraw money from the funds to be cash equivalents.

Property and Equipment

In January 2010, the Financial Accounting Standards Board (‘‘FASB’’) issued oil and natural gas reserves estimation and disclosure authoritative accounting guidance effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and natural gas reserves estimation and disclosure requirements with the requirements in the Securities and Exchange Commission’s (‘‘SEC’’) final rule, ‘‘Modernization of Oil and Gas Reporting’’, which was also effective for annual reports for fiscal years ending on or after December 31, 2009. These rules included, among other things, changes to pricing used to estimate oil and natural gas reserves, broadened the types of technologies that a company may use to establish oil and natural gas reserves estimates, and broadened the definition of oil and natural gas producing activities. Accordingly, the Company adopted both the FASB’s authoritative accounting guidance and the SEC’s rule as of December 31, 2009.

The Company uses the full cost method of accounting for oil and gas properties. Separate cost centers are maintained for each country in which the Company has operations. During the periods presented, the Company's primary oil and gas operations were conducted in the United States and Canada. Upon the spin-off of Lone Pine on September 30, 2011, the Company no longer has any operations in Canada. All costs incurred in the acquisition, exploration, and development of

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properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) and the fair value of estimated future costs of site restoration, dismantlement, and abandonment activities are capitalized. For the years ended December 31, 2011, 2010, and 2009, Forest's continuing operations capitalized $46.4 million, $42.6 million, and $41.5 million of general and administrative costs (including stock-based compensation), respectively. Interest costs related to significant unproved properties that are under development are also capitalized to oil and gas properties. During 2011, 2010, and 2009, Forest's continuing operations capitalized $10.3 million, $11.2 million, and $12.2 million, respectively, of interest costs attributed to unproved 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 estimated 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. The amount of impairment assessed is added to the costs to be amortized, or is reported as a period expense, as appropriate.

The Company performs a ceiling test each quarter on a country-by-country basis. 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 ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for each cost center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and 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 gas properties. Should the net capitalized costs 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 December 31, 2011 ceiling test did not result in a write-down. The March 31, 2009 ceiling test resulted in a non-cash write-down of oil and gas property costs of $1.4 billion in the United States cost center.

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

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, as adjusted for future development costs and asset retirement obligations, are amortized over the total estimated proved reserves. The Company has historically updated its quarterly depletion calculations with its quarter-end reserves estimates. Based on this accounting policy, the December 31, 2011 reserves estimates were used for the Company's fourth quarter 2011 depletion calculation.

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, leasehold improvements, computer hardware and software, and other equipment are depreciated on the straight-line method over the estimated useful lives of the assets, which range from three to fifteen years.

Asset Retirement Obligations

Forest records the fair value of a liability for an asset retirement obligation in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. Subsequent to initial measurement, the asset retirement obligation is required to be accreted each period to its present value. Capitalized costs are depleted as a component of the full cost pool using the units-of-production method. Forest's asset retirement obligations consist of costs related to the plugging of wells, the removal of facilities and equipment, and site restoration on oil and gas properties.

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The following table summarizes the activity for the Company's asset retirement obligations of its continuing operations for the periods indicated:

| | Year Ended December 31, 2011 | 2010 |
|---|---|---|
| | (In Thousands) | |
| Asset retirement obligations at beginning of period | $73,132 | $78,487 |
| Accretion expense | 6,082 | 6,158 |
| Liabilities incurred | 2,321 | 1,988 |
| Liabilities settled | (3,103) | (4,009) |
| Disposition of properties | (282) | (6,423) |
| Revisions of estimated liabilities | 788 | (3,069) |
| Asset retirement obligations at end of period | 78,938 | 73,132 |
| Less: current asset retirement obligations | (1,040) | (121) |
| Long-term asset retirement obligations | $77,898 | $73,011 |

Oil, Natural Gas, and NGL Sales

The Company recognizes revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred, (iii) the Company's price to the buyer is fixed or determinable and (iv) collectibility is reasonably assured.

When the Company has an interest with other producers in properties from which natural gas is produced, the Company uses the entitlements method to account for any imbalances. Imbalances occur when the Company sells more or less product than it is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that the Company sells in excess of its entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount the Company sells is recognized as revenue and a receivable is accrued. At December 31, 2011 and 2010, the Company had gas imbalance payables of $7.8 million and $7.7 million, respectively, and gas imbalance receivables of $6.9 million and $7.0 million, respectively.

In 2011, sales to one purchaser were approximately 22%, or $151.9 million, of the Company's total revenues from continuing operations. In 2010, sales to two purchasers were approximately 20%, or $145.1 million, and 10%, or $73.2 million, respectively, of the Company's total revenues from continuing operations. In 2009, sales to two purchasers were approximately 17%, or $108.6 million, and 10%, or $66.9 million, respectively, of the Company's total revenues from continuing operations. Forest's revenues from continuing operations are attributable to the United States. Forest believes that the loss of one or more of the Company's current oil, natural gas, and NGL 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.

Accounts Receivable

The components of accounts receivable related to continuing operations are as follows:

| | December 31, 2011 | 2010 |
|---|---|---|
| | (In Thousands) | |
| Oil, natural gas, and NGL sales | $58,799 | $61,538 |
| Joint interest billings | 14,451 | 15,877 |
| Tax incentive refunds due from Texas | 6,604 | 14,291 |
| Other | 698 | 12,440 |
| Allowance for doubtful accounts | (1,463) | (1,821) |
| Total accounts receivable | $79,089 | $102,325 |

Forest's accounts receivable are primarily from purchasers of the Company's oil, natural gas, and NGL sales and from other exploration and production companies which own working interests in the properties that the Company operates. This industry concentration could adversely impact Forest's overall credit risk because the Company's customers and working

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interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices, and other conditions. Forest's oil, natural gas, and NGL 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. Forest 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. Forest routinely assesses the collectibility of all material receivables and accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve can be reasonably estimated.

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. 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.

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 to be used since Forest has participating securities. 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 Forest's stock incentive plans have the right to receive non-forfeitable cash and certain non-cash dividends, participating on an equal basis with common stock. Holders of phantom stock units issued to directors under Forest's stock incentive plans also have the right to receive non-forfeitable cash and certain non-cash dividends, participating on an equal basis with common stock, while phantom stock units issued to employees do not participate in dividends. Stock options issued under Forest's stock incentive plans do not participate in dividends. Performance units issued under Forest's stock incentive plans do not participate in dividends in their current form. Holders of performance units participate in dividends paid during the performance units' vesting period only after the performance units vest with common shares being earned by the holders of the performance units. Performance units may vest with no common shares being earned, depending on Forest's shareholder return over the performance units' vesting period in relation to the shareholder returns of specified peers. See Note 6 for more information on Forest's stock-based incentive awards. In summary, restricted stock issued to employees and directors and phantom stock units issued to directors 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 Forest's losses. Therefore, in periods of net loss, none of the loss is allocated to these participating securities.

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 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 (e.g. stock options, unvested restricted stock grants, unvested phantom stock units that may be settled in shares, and unvested performance units). No potential common shares are included in the computation of any diluted per share amount when a net loss exists. Unvested restricted stock grants were not included in the calculations of diluted earnings per share for the years ended December 31, 2011 and 2010 as their inclusion would have an antidilutive effect. Stock options, unvested restricted stock grants, and unvested phantom stock units that may be settled in shares were not included in the calculation of diluted loss per share for the year ended December 31, 2009 as their inclusion would have an antidilutive effect.

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The following reconciles net earnings (loss) as reported in the Consolidated Statements of Operations to net earnings (loss) used for calculating basic and diluted earnings (loss) per share for the periods presented.

| | Year Ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | | | 2010 | | | 2009 | | |
| | Continuing Operations | Discontinued Operations | Total | Continuing Operations | Discontinued Operations | Total | Continuing Operations | Discontinued Operations | Total |
| | (In Thousands) | | | | | | | | |
| Net earnings (loss) | $98,260 | $44,569 | $142,829 | $189,662 | $37,859 | $227,521 | $(793,789) | $(129,344) | $(923,133) |
| Net earnings attributable to noncontrolling interest | — | (4,987) | (4,987) | — | — | — | — | — | — |
| Net earnings attributable to participating securities | (2,037) | (821) | (2,858) | (3,736) | (746) | (4,482) | — | — | — |
| Net earnings (loss) attributable to common stock for basic earnings (loss) per share | 96,223 | 38,761 | 134,984 | 185,926 | 37,113 | 223,039 | (793,789) | (129,344) | (923,133) |
| Adjustment for liability classified stock-based compensation awards | — | (707) | (707) | — | 500 | 500 | — | — | — |
| Net earnings (loss) for diluted earnings (loss) per share | $96,223 | $38,054 | $134,277 | $185,926 | $37,613 | $223,539 | $(793,789) | $(129,344) | $(923,133) |

The following reconciles basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the periods presented.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| Weighted average common shares outstanding during the period for basic earnings (loss) per share | 111,690 | 110,809 | 104,336 |
| Dilutive effects of potential common shares | 1,178 | 689 | — |
| Weighted average common shares outstanding during the period, including the effects of dilutive potential common shares, for diluted earnings (loss) per share | 112,868 | 111,498 | 104,336 |

Stock-Based Compensation

Compensation cost is measured at the grant date based on the fair value of the awards (stock options, restricted stock, performance units, employee stock purchase plan rights) or is measured at the reporting date based on the current stock price (phantom stock units), and is recognized on a straight-line basis over the requisite service period (usually the vesting period).

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 statements of operations together with realized gains and losses on the derivative instruments.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and our revolving bank credit facility. The remaining unamortized debt issue costs at December 31, 2011 and 2010 totaled $25.0 million and $23.9 million, respectively, and are being amortized over the life of the respective debt instruments.

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Inventory

Inventories, which are carried at average cost with adjustments made from time to time to recognize, as appropriate, any reductions in value, were comprised of $10.1 million and $22.6 million of materials and supplies as of December 31, 2011 and 2010, respectively. The Company's materials and supplies inventory, which is acquired for use in future drilling operations, is primarily comprised of items such as tubing and casing.

Goodwill

The Company is required to make an annual impairment assessment of goodwill in lieu of periodic amortization. The Company performs its annual goodwill impairment test in the second quarter of the 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 reserves 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. The Company had no goodwill impairments for the years ended December 31, 2011, 2010, and 2009.

Comprehensive Earnings (Loss)

Comprehensive earnings (loss) is a term used to refer to net earnings (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under generally accepted accounting principles are reported as separate components of shareholders' equity instead of net earnings (loss). Items included in the Company's other comprehensive income (loss) during the last three years are net foreign currency gains and losses related to the translation of the assets and liabilities of Lone Pine's Canadian operations prior to the spin-off of Lone Pine on September 30, 2011, and changes in the unfunded postretirement benefits.

The components of accumulated other comprehensive income (loss) for the years ended December 31, 2011, 2010, and 2009 are as follows:

| | Foreign Currency Translation | Unfunded Postretirement Benefits[(1)] | Accumulated Other Comprehensive Income (Loss) |
|---|---|---|---|
| | (In Thousands) | | |
| Balance at January 1, 2009 | $50,607 | $(13,009) | $37,598 |
| 2009 activity | 27,907 | 2,152 | 30,059 |
| Balance at December 31, 2009 | 78,514 | (10,857) | 67,657 |
| 2010 activity | 15,153 | (746) | 14,407 |
| Balance at December 31, 2010 | 93,667 | (11,603) | 82,064 |
| 2011 activity | (93,667) | (6,669) | (100,336) |
| Balance at December 31, 2011 | $— | $(18,272) | $(18,272) |

(1) Net of income tax expense (benefit) of $(3.7) million, $(.5) million, and $1.2 million for 2011, 2010, and 2009, respectively.

Impact of Recently Issued Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income, Presentation of Comprehensive Income (“ASU 2011-05”), which provides amendments that will result in more converged guidance on how comprehensive income is presented under U.S. generally accepted accounting principles (“U.S. GAAP”) and International Financial Reporting Standards (“IFRS”). ASU 2011-05 requires an entity 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 eliminates the option to report other comprehensive income and its components in the statement of shareholders’ equity. ASU 2011-05 also requires entities 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. 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 ASU 2011-05 to present on the face of the financial statements the effects of reclassifications out of accumulated other

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comprehensive income on the components of net income and other comprehensive income. Both ASU 2011-05 and ASU 2011-12 are effective for interim and annual periods beginning after December 15, 2011, and should be applied retrospectively. The adoption of this authoritative guidance will not have an impact on Forest's financial position or results of operations, but will require Forest to present the statements of comprehensive income separately from the statements of shareholders' equity, as these statements are currently presented on a combined basis.

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 U.S. GAAP fair value measurement and disclosure guidance, to converge U.S. 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. Forest is currently evaluating the impact that the adoption of this authoritative guidance will have on its fair value measurements and disclosures.

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment ("ASU 2011-08"), 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 Forest 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 comparison between U.S. GAAP and IFRS financial statements by requiring enhanced disclosures, but does not change existing U.S. 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. The adoption of this authoritative guidance will not have an impact on Forest's financial position or results of operations, but will require Forest to make enhanced disclosures regarding its derivative instruments.

(2) PROPERTY AND EQUIPMENT:

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

| | December 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (In Thousands) | |
| Oil and gas properties: | | |
| Proved | $8,825,142 | $8,058,876 |
| Unproved | 675,995 | 646,264 |
| Accumulated depletion | (6,901,997) | (6,688,012) |
| Net oil and gas properties | 2,599,140 | 2,017,128 |
| Other property and equipment: | | |
| Gas gathering, furniture and fixtures, computer hardware and software, and other equipment | 99,965 | 95,577 |
| Accumulated depreciation and amortization | (47,989) | (42,432) |
| Net other property and equipment | 51,976 | 53,145 |

| | | |
|---|---|---|
| Total net property and equipment[(1)] | $2,651,116 | $2,070,273 |

(1) At December 31, 2011 and 2010, $98.7 million and $91.6 million, respectively, of the Company's total net property and equipment of continuing operations was located in foreign countries. The remaining total net property and equipment was located in the United States.

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

| | Total | 2011 | 2010 | 2009 | 2008 and Prior |
|---|---|---|---|---|---|
| | (In Thousands) | | | | |
| United States: | | | | | |
| Acquisition costs | $539,439 | $171,137 | $27,394 | $29,894 | $311,014 |
| Exploration costs | 71,661 | 59,886 | 3,861 | 1,786 | 6,128 |
| Total United States | 611,100 | 231,023 | 31,255 | 31,680 | 317,142 |
| International: | | | | | |
| Acquisition costs | 740 | — | — | — | 740 |
| Exploration costs | 64,155 | 5,767 | 1,968 | 1,451 | 54,969 |
| Total International | 64,895 | 5,767 | 1,968 | 1,451 | 55,709 |
| Total | $675,995 | $236,790 | $33,223 | $33,131 | $372,851 |

The majority of the U.S. unproved oil and gas property costs, or those not being depleted, relate to oil and gas property acquisitions and leasehold acquisition costs as well as work-in-progress on various projects. The Company expects that substantially all of its unproved property costs in the U.S. as of December 31, 2011 will be reclassified to proved properties within ten years. Forest's exploration project in South Africa accounts for all of the international costs not being amortized as of December 31, 2011. The Company continues to pursue commercial development of the Ibhubesi field discovery in South Africa including continued efforts toward securing gas sales contracts.

Divestitures

During the years ended December 31, 2011 and 2010, Forest sold various U.S. oil and natural gas properties for total proceeds of $121.0 million and $75.9 million, respectively. During 2010, Forest also entered into sale-leaseback transactions involving drilling rigs, receiving $63.1 million in total proceeds. During 2009, Forest sold all of its oil and natural gas properties located in the Permian Basin in West Texas and New Mexico for approximately $908.3 million in cash and also sold other
U.S. oil and natural gas properties for total proceeds of $25.0 million.

Acquisitions - Subsequent Event

In February 2012, the Company paid $66.0 million in cash and issued 2.7 million shares of common stock, valued at approximately $36 million, pursuant to a lease purchase agreement whereby Forest acquired leases on unproved oil and natural gas properties in the Wolfbone oil play in the Permian Basin in Texas.

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(3) DEBT:

The components of debt are as follows:

| | December 31, 2011 | | | December 31, 2010 | | | |
|---|---|---|---|---|---|---|---|
| | Principal | Unamortized Premium (Discount) | Total | Principal | Unamortized Premium (Discount) | Other[1] | Total |
| | (In Thousands) | | | | | | |
| Credit Facility | $105,000 | $— | $105,000 | $— | $— | $— | $— |
| 8% Senior Notes due 2011[2] | — | — | — | 285,000 | 1,292 | 800 | 287,092 |
| 7% Senior Subordinated Notes due 2013 | 12 | — | 12 | 12 | — | — | 12 |
| 8½% Senior Notes due 2014 | 600,000 | (12,389) | 587,611 | 600,000 | (18,210) | — | 581,790 |
| 7¼% Senior Notes due 2019 | 1,000,000 | 421 | 1,000,421 | 1,000,000 | 478 | — | 1,000,478 |
| Total debt | 1,705,012 | (11,968) | 1,693,044 | 1,885,012 | (16,440) | 800 | 1,869,372 |
| Less: current portion of long-term debt | — | — | — | (285,000) | (1,292) | (800) | (287,092) |
| Long-term debt | $1,705,012 | $(11,968) | $1,693,044 | $1,600,012 | $(17,732) | $— | $1,582,280 |

(1) Represents the unamortized portion of deferred gains realized upon the termination of interest rate swaps in 2002 that were accounted for as fair value hedges. The gains were amortized as a reduction of interest expense over the terms of the notes.

(2) Redeemed in December 2011.

Bank Credit Facility

On June 30, 2011, the Company entered into the Third Amended and Restated Credit Agreement (the "Credit Facility") with a syndicate of banks led by JPMorgan Chase Bank, N.A., consisting of a $1.5 billion credit facility maturing in June 2016. Subject to the agreement of Forest and the applicable lenders, the size of the Credit Facility may be increased by $300.0 million, to a total of $1.8 billion.

Forest's availability under the Credit Facility is governed by a borrowing base. As of December 31, 2011, the borrowing base under the Credit Facility was $1.25 billion. The determination of the borrowing base is made by the lenders in their sole discretion, on a semi-annual basis, taking into consideration the estimated value of Forest's oil and gas properties based on pricing models determined by the lenders at such time, in accordance with the lenders' customary practices for oil and gas loans. The available borrowing amount under the Credit Facility could increase or decrease based on such redetermination. In addition to the scheduled semi-annual redeterminations, Forest and the lenders each have discretion at any time, but not more often than once during a calendar year, to have the borrowing base redetermined. The borrowing base is also subject to automatic adjustments if certain events occur. The borrowing base was reaffirmed at $1.25 billion in October 2011 and the next scheduled redetermination of the borrowing base will occur on or about May 1, 2012.

The borrowing base is also subject to change in the event (i) Forest or 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 notes, excluding any senior unsecured notes that Forest or any of its Restricted Subsidiaries may issue to refinance then-existing senior notes, or (ii) Forest 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. A lowering of the borrowing base could require Forest to repay indebtedness in excess of the borrowing base in order to cover the deficiency.

Borrowings under the Credit Facility bear interest at one of two rates as may be elected by the Company. Borrowings bear interest at:

(i) the greatest of (a) the prime rate announced by JPMorgan Chase Bank, N.A., (b) the federal funds effective rate from time to time plus ½ of 1%, and (c) the one-month rate applicable to dollar deposits in the London interbank market for one, two, three or six months (as selected by Forest) (the "LIBO Rate") plus 1%, plus, in the case of each of clauses (a), (b), and (c), 50 to 150 basis points depending on borrowing base utilization; or

(ii) the LIBO Rate as adjusted for statutory reserve requirements (the "Adjusted LIBO Rate"), plus 150 to 250 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, mergers, and acquisitions, and also includes a financial covenant. The Credit Facility provides that Forest will not permit its ratio of total debt outstanding to consolidated EBITDA (as adjusted for non-cash charges) for a trailing twelve-month period to be greater than 4.50 to 1.00 at any time.

Under certain conditions, amounts outstanding under the Credit Facility may be accelerated. Bankruptcy and insolvency events with respect to Forest or certain of its 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 Credit 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 Forest’s assets. Under the Credit Facility, Forest is required to mortgage and grant a security interest in 75% of the present value of the estimated proved oil and gas properties and related assets of Forest and its U.S. subsidiaries. Forest is required to pledge, and has pledged, the stock of certain subsidiaries to secure the Credit Facility. If Forest’s corporate credit rating by Moody’s and S&P meet pre-established levels, the security requirements would cease to apply and, at Forest’s request, the banks would release their liens and security interest on Forest’s properties.

Of the $1.5 billion total nominal amount under the Credit Facility, JPMorgan and eleven other banks hold approximately 68% of the total commitments, with each of these twelve lenders holding an equal share. With respect to the other 32% of the total commitments, no single lender holds more than 3.3% of the total commitments.

Commitment fees accrue on the amount of unutilized borrowing base. If borrowing base utilization is greater than 50%, commitment fees are 50 basis points of the unutilized amount, and if borrowing base utilization is 50% or less, commitment fees are 35 basis points of the unutilized amount.

At December 31, 2011, there were outstanding borrowings of $105.0 million under the Credit Facility at a weighted average interest rate of 2.1% and Forest had used the Credit Facility for $2.1 million in letters of credit, leaving an unused borrowing amount under the Credit Facility of $1.1 billion.

Prior to entering into the Credit Facility, the previous combined credit facility, the Second Amended and Restated Credit Agreement dated as of June 6, 2007, consisting of U.S. and Canadian facilities (the “Combined Credit Facility”) was amended on May 25, 2011, to, among other things, remove any collateral owned by Lone Pine or any of its subsidiaries from the collateral securing the U.S. portion of the Combined Credit Facility, terminate the previous Canadian portion of the Combined Credit Facility, terminate various guaranties securing the Canadian portion of the Combined Credit Facility, release collateral securing the Canadian portion of the Combined Credit Facility, and terminate certain liens and mortgages securing the Canadian portion of the Combined Credit Facility.

8½% Senior Notes Due 2014

On February 17, 2009, Forest issued $600.0 million in principal amount of 8½% senior notes due 2014 (the "8½% Notes") at 95.15% of par for net proceeds of $559.8 million, after deducting initial purchaser discounts. The 8½% Notes are redeemable, at the Company's option, in whole or in part, at any time at the principal amount, plus accrued interest, and a make-whole premium. Due to the amortization of the discount, the effective interest rate on the 8½% Notes is 9.47%.

7¼% Senior Notes Due 2019

On June 6, 2007, Forest issued $750.0 million in principal amount of 7¼% senior notes due 2019 (the "7¼% Notes") at par for net proceeds of $739.2 million, after deducting initial purchaser discounts, and on May 22, 2008, Forest issued an additional $250.0 million in principal amount of 7¼% Notes at 100.25% of par for net proceeds of $247.2 million, after deducting initial purchaser discounts. Due to the amortization of the premium, the effective interest rate on the 7¼% Notes is 7.24%.

Forest may redeem the 7¼% Notes at any time beginning on or after June 15, 2012 at the prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued but unpaid interest:

| | | |
|---|---|---|
| 2012 | 103.6 | % |
| 2013 | 102.4 | % |
| 2014 | 101.2 | % |
| 2015 and thereafter | 100.0 | % |

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Forest may also redeem the 7¼% Notes, in whole or in part, at a price equal to the principal amount plus a make-whole premium, at any time prior to June 15, 2012, using a discount rate of the Treasury rate plus 0.50%, plus accrued but unpaid interest.

8% Senior Notes Due 2011

In December 2001, Forest issued $160.0 million in principal amount of 8% senior notes due 2011 (the "8% Notes") at par for proceeds of $157.5 million (net of related offering costs). In July 2004, Forest issued an additional $125.0 million in principal amount of 8% Notes at 107.75% of par for proceeds of $133.3 million (net of related offering costs). In December 2011, Forest redeemed the 8% Notes.

7¾% Senior Notes Due 2014

In December 2009, Forest notified the trustee and note holders of the $150.0 million of 7¾% senior notes due 2014 (the "7¾% Notes") that it was calling the 7¾% Notes. This notice was irrevocable after it was given.

The 7¾% Notes were redeemed in January 2010 at 101.292% of par and a net gain of $4.6 million was recognized in January 2010 upon redemption. The net gain was recognized due to the write-off of unamortized deferred gains that resulted from the previous termination of interest rate swaps related to the 7¾% Notes.

Principal Maturities

Principal maturities of the Company's debt at December 31, 2011 are as follows:

| | Principal Maturities (In Thousands) |
|---|---|
| 2012 | $— |
| 2013 | 12 |
| 2014 | 600,000 |
| 2015 | — |
| 2016 | 105,000 |
| Thereafter | 1,000,000 |

(4) INCOME TAXES:

Income Tax Provision

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| Current: | | | |
| Federal | $(201) | $(16,393) | $62,366 |
| Foreign | 28,921 | — | — |
| State | 1,421 | 2,492 | 8,449 |
| | 30,141 | (13,901) | 70,815 |
| Deferred: | | | |
| Federal | 56,482 | 121,111 | (525,739) |
| State | 2,512 | 2,560 | (11,677) |
| | 58,994 | 123,671 | (537,416) |
| | $89,135 | $109,770 | $(466,601) |

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Income (loss) from continuing operations before income taxes consists of the following for the periods presented:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| United States Federal | $188,421 | $301,349 | $(1,259,729) |
| Foreign | (1,026) | (1,917) | (661) |
| | $187,395 | $299,432 | $(1,260,390) |

A reconciliation of reported income tax attributable to continuing operations to the amount of income tax that would result from applying the United States federal statutory income tax rate to pretax income from continuing operations is as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| Federal income tax at 35% of income before income taxes and discontinued operations | $65,947 | $105,472 | $(440,905) |
| State income taxes, net of federal income tax benefits | 2,214 | 3,526 | (14,080) |
| Change in the valuation allowance for deferred tax assets | — | — | (8,913) |
| Canadian dividend tax, net of U.S. tax benefit | 18,460 | — | — |
| Effect of federal, state, and foreign tax on permanent differences | 4,025 | 4,030 | 1,725 |
| Other | (1,511) | (3,258) | (4,428) |
| Total income tax | $89,135 | $109,770 | $(466,601) |

Net Deferred Tax Assets and Liabilities

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

| | December 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (In Thousands) | |
| Deferred tax assets: | | |
| Property and equipment | $93,032 | $139,992 |
| Investment in PERL common stock and Note | — | 18,011 |
| Accrual for postretirement benefits | 11,545 | 7,831 |
| Stock-based compensation accruals | 7,921 | 15,471 |
| Net operating loss carryforwards | 60,965 | 42,992 |
| Alternative minimum tax credit carryforward | 54,776 | 54,584 |
| Other | 8,418 | 9,803 |
| Total gross deferred tax assets | 236,657 | 288,684 |
| Less valuation allowance | — | — |
| Net deferred tax assets | 236,657 | 288,684 |
| Deferred tax liabilities: | | |
| Unrealized gains on derivative contracts, net | (25,713) | (11,574) |
| Total gross deferred tax liabilities | (25,713) | (11,574) |
| Net deferred tax assets | $210,944 | $277,110 |

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The net deferred tax assets and liabilities are reflected in the Consolidated Balance Sheets as follows:

| | December 31, | |
|---|---|---|
| | 2011 | 2010 |
| | (In Thousands) | |
| Current deferred tax liabilities | $(20,172) | $(6,911) |
| Non-current deferred tax assets | 231,116 | 284,021 |
| Net deferred tax assets | $210,944 | $277,110 |

Tax Attributes

Net Operating Losses

U.S. federal net operating loss carryforwards ("NOLs") at December 31, 2011 were approximately $169.7 million, with $8.2 million scheduled to expire in 2019, $1.4 million scheduled to expire in 2020, and the remaining scheduled to expire after 2030.

The statute of limitations is closed for the Company's U.S. federal income tax returns for years ending on or before December 31, 2007. Pre-acquisition returns of acquired businesses are also closed for tax years ending on or before December 31, 2007. However, the Company has utilized, and will continue to utilize, NOLs (including NOLs of acquired businesses) in its open tax years. The earliest available NOLs were generated in the tax year beginning January 1, 1999, but are potentially subject to adjustment by the federal tax authorities in the tax year in which they are utilized. Thus, the Company's earliest U.S. federal income tax return that is closed to potential audit adjustment is the tax year ending December 31, 1999.

Alternative Minimum Tax Credits

The Alternative Minimum Tax credit carryforward available to reduce future U.S. federal regular taxes equaled an aggregate amount of $54.8 million at December 31, 2011, which can be carried forward indefinitely.

Accounting for Uncertainty in Income Taxes

The table below sets forth the reconciliation of the beginning and ending balances of the total amounts of unrecognized tax benefits. The Company records interest accrued related to unrecognized tax benefits in interest expense and penalties in other expense, to the extent they apply. The Company does not expect a material amount of unrecognized tax benefits to reverse in the next twelve months.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | (In Thousands) | | |
| Gross unrecognized tax benefits at beginning of period | $3,345 | $2,665 | $3,167 |
| Increases as a result of tax positions taken during a prior period | — | 1,078 | 1,138 |
| Decreases as a result of tax positions taken during a prior period | (516) | (398) | (1,640) |
| Gross unrecognized tax benefits at end of period | $2,829 | $3,345 | $2,665 |

(5) SHAREHOLDERS' EQUITY:

Common Stock

At December 31, 2011, the Company had 200.0 million shares of common stock, par value $.10 per share, authorized and 114.5 million shares issued and outstanding.

In May 2009, the Company issued 14.4 million shares of common stock at a price of $18.25 per share. Net proceeds from this offering were $256.2 million after deducting underwriting discounts and commissions and offering expenses.

In February 2012, the Company issued 2.7 million shares of common stock, valued at approximately $36 million, as partial consideration pursuant to a lease purchase agreement whereby Forest acquired leases on unproved oil and natural gas properties in the Wolfbone oil play in the Permian Basin in Texas.

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Preferred Stock

Forest has 10.0 million shares of preferred stock, par value $.01 per share, authorized under its Articles of Incorporation. Of those, 7.4 million shares are designated as Senior Preferred Stock and 2.7 million shares are designated as Junior Preferred stock. No preferred stock is issued or outstanding.

Lone Pine

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 Forest's remaining shares of Lone Pine to Forest's shareholders. In May 2011, as part of a corporate restructuring in anticipation of Lone Pine’s initial public offering, Lone Pine Resources Canada Ltd. (“LPR Canada”), Forest’s former Canadian subsidiary, declared a stock dividend to Forest immediately before Forest’s contribution of LPR Canada to Lone Pine, with such stock dividend resulting in Forest incurring a dividend tax payable to Canadian federal tax authorities of $28.9 million, which Forest paid in June 2011. This dividend tax is classified within “Income tax” on the Consolidated Statement of Operations. On June 1, 2011, Lone Pine completed an initial public offering of 15 million shares of its common stock at a price of $13.00 per share ($12.22 per share net of underwriting discounts and commissions). Upon completion of the offering, Forest retained controlling interest in Lone Pine, owning approximately 82% of the outstanding shares of Lone Pine’s common stock. The net proceeds from the offering received by Lone Pine, after deducting underwriting discounts and commissions and offering expenses, were approximately $178.0 million. Lone Pine used the net proceeds to pay $29.2 million to Forest as partial consideration for Forest’s contribution to Lone Pine of Forest’s direct and indirect interests in its Canadian operations. Additionally, Lone Pine used the remaining net proceeds and borrowings under Lone Pine’s credit facility to repay Lone Pine’s outstanding indebtedness owed to Forest, consisting of a note payable, intercompany advances, and accrued interest, of $400.5 million. Forest completed the spin-off of its remaining shares of Lone Pine on September 30, 2011, in the form of a pro rata common stock dividend to all Forest shareholders of record as of the close of business on September 16, 2011 (the “Record Date”). Forest shareholders received .61248511 of a share of Lone Pine common stock for every share of Forest common stock held as of the close of business on the Record Date. In accordance with applicable authoritative accounting guidance, Forest accounted for the spin-off based on the carrying value of Lone Pine.

The table below sets forth the effects of changes in Forest’s ownership interest in Lone Pine on Forest’s equity, during the 2011 period in which Forest had an ownership interest in Lone Pine up to its spin-off on September 30, 2011.

| | Nine Months Ended September 30, 2011 (In Thousands) |
|---|---|
| Net earnings attributable to Forest Oil Corporation | $118,375 |
| Transfers from (to) the noncontrolling interest: | |
| Increase in Forest Oil Corporation’s capital surplus for sale of 15 million Lone Pine Resources Inc. common shares | 112,610 |
| Decrease in Forest Oil Corporation’s capital surplus for spin-off of 70 million Lone Pine Resources Inc. common shares | (333,568) |
| Change from net earnings attributable to Forest Oil Corporation and transfers from (to) noncontrolling interest | $(102,583) |

Rights Agreement

In October 1993, the Board of Directors of Forest adopted a shareholders' rights plan and entered into a Rights Agreement (the "1993 Agreement"), which was amended and supplemented in October 2003 by the First Amended and Restated Rights Agreement (taken together with the 1993 Agreement, the "Rights Agreement"). Under the Rights Agreement, one Preferred Share Purchase Right (the "Rights") is issued for each outstanding share of the Company's common stock. The Rights expire on October 29, 2013, unless earlier exchanged or redeemed. The Rights entitle the holder thereof to purchase 1/100th of a preferred share at an initial purchase price of $120 and are exercisable only if a person or group acquires 20% or more of the Company's common stock or announces a tender offer that would result in ownership by a person or group of 20% or more of the common stock.

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(6) STOCK-BASED COMPENSATION:

Stock-based Compensation Plans

In 2001, the Company adopted the Forest Oil Corporation 2001 Stock Incentive Plan (the "2001 Plan") and in 2007, the Company adopted the Forest Oil Corporation 2007 Stock Incentive Plan (the "2007 Plan" and together with the 2001 Plan the "Stock-based Compensation Plans") under which qualified and non-qualified stock options, restricted stock, performance units, phantom stock units, and other awards may be granted to employees, consultants, and non-employee directors. The aggregate number of shares of common stock that the Company may issue under the 2007 Plan may not exceed 8.7 million shares. As of December 31, 2011, the Company had 4.1 million shares available to be issued under the 2007 Plan. The aggregate number of shares of common stock that the Company could issue under the 2001 Plan was 5.0 million, of which there are no remaining shares to be issued at December 31, 2011.

Compensation Costs

The table below sets forth stock-based compensation of continuing operations recorded during the years ended December 31, 2011, 2010, and 2009, and the remaining unamortized amounts and weighted average amortization period as of December 31, 2011.

| | Stock Options(1) | Restricted Stock(2) | Performance Units | Phantom Stock Units | | Total(3)(4) |
|---|---|---|---|---|---|---|
| | (In Thousands) | | | | | |
| Year ended December 31, 2011: | | | | | | |
| Total stock-based compensation costs | $1,536 | $30,234 | $3,178 | $156 | | $35,104 |
| Less: stock-based compensation costs capitalized | (663) | (13,113) | (957) | (134) | | (14,867) |
| Stock-based compensation costs expensed | $873 | $17,121 | $2,221 | $22 | | $20,237 |
| Unamortized stock-based compensation costs as of December 31, 2011 | $— | $21,121 | $7,260 | $11,293 | (5) | $39,674 |
| Weighted average amortization period remaining as of December 31, 2011 | — | 2.0 | 1.7 | 1.8 | | 1.9 |
| Year ended December 31, 2010: | | | | | | |
| Total stock-based compensation costs | $563 | $25,377 | $1,907 | $3,129 | | $30,976 |
| Less: stock-based compensation costs capitalized | (241) | (9,492) | (469) | (1,010) | | (11,212) |
| Stock-based compensation costs expensed | $322 | $15,885 | $1,438 | $2,119 | | $19,764 |
| Year ended December 31, 2009: | | | | | | |
| Total stock-based compensation costs | $774 | $25,448 | $— | $1,000 | | $27,222 |
| Less: stock-based compensation costs capitalized | (311) | (10,301) | — | (322) | | (10,934) |
| Stock-based compensation costs expensed | $463 | $15,147 | $— | $678 | | $16,288 |

(1) In conjunction with the spin-off of Lone Pine, both the number of options outstanding and the option exercise prices were adjusted in accordance with antidilution provisions provided for by the Stock-based Compensation Plans, which were designed to equalize an award’s value before and after an equity restructuring. Because the actual option modifications were calculated based on Forest’s average stock price over a period of time before and after the spin-off of Lone Pine rather than the stock price immediately before and after the spin-off, $1.1 million in incremental compensation cost resulted, $.4 million of which was capitalized. This cost was recognized in its entirety on September 30, 2011 because all options outstanding were vested as of that date.

(2) In conjunction with the spin-off, the forfeiture restrictions on a portion of each outstanding restricted stock award lapsed because the holders of the restricted stock awards received unrestricted Lone Pine common shares in the spin-off. This resulted in an acceleration of the recognition of $10.9 million of compensation costs associated with the restricted stock awards, $4.9 million of which was capitalized.

(3) The Company also maintains an employee stock purchase plan (which is not included in the table) under which \$.5 million, \$.5 million, and \$.6 million of compensation costs were recognized for the years ended December 31, 2011, 2010, and 2009, respectively.

(4) In addition to the compensation costs set forth in the table above, in June 2011 the Company granted a cash-based long-term incentive award under which \$.1 million in compensation costs were recognized for the year ended December 31, 2011, and under which \$.5 million remains as unamortized stock-based compensation costs at December 31, 2011.  The award is comprised of time-based and performance-based components.  Under the time-based component, a cash payment will be made after three years dependent on the change in value of Forest’s common stock during the three-year period, and under the performance-based component, a cash payment will be made after three years dependent on the total shareholder return on Forest’s common stock in comparison to that of a peer group during the three-year period. The cash-based long-term incentive award has been accounted for as a liability within the Consolidated Financial Statements.

(5) Based on the closing price of the Company's common stock on December 31, 2011.

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Stock Options

The following table summarizes stock option activity in the Stock-based Compensation Plans for the years ended December 31, 2011, 2010, and 2009.

| | Number of Options | Weighted Average Exercise Price | Aggregate Intrinsic Value (In Thousands)[(2)] | Number of Options Exercisable |
|---|---|---|---|---|
| Outstanding at January 1, 2009 | 2,097,267 | $21.13 | $376 | 1,898,316 |
| Granted | — | — | | |
| Exercised | (170,702) | 17.96 | 671 | |
| Cancelled | (108,146) | 23.82 | | |
| Outstanding at December 31, 2009 | 1,818,419 | 21.26 | 7,387 | 1,722,216 |
| Granted | — | — | | |
| Exercised | (457,974) | 18.99 | 6,027 | |
| Cancelled | (32,750) | 36.28 | | |
| Outstanding at December 31, 2010 | 1,327,695 | 21.67 | 22,531 | 1,283,232 |
| Granted | — | — | | |
| Exercised | (29,711) | 18.55 | 331 | |
| Cancelled | (13,273) | 25.11 | | |
| Spin-off adjustment[(1)] | 673,189 | | | |
| Outstanding at September 30, 2011 | 1,957,900 | 14.29 | 187 | 1,957,900 |
| Granted | — | — | | |
| Exercised | (161,834) | 11.32 | 634 | |
| Cancelled | (29,479) | 14.86 | | |
| Outstanding at December 31, 2011 | 1,766,587 | $14.55 | $2,731 | 1,766,587 |

(1) In conjunction with the spin-off of Lone Pine, both the number of options outstanding and the option exercise prices were adjusted in accordance with antidilution provisions provided for by the Stock-based Compensation Plans. In conjunction with the spin-off, Lone Pine employees were deemed to have been involuntarily terminated under the terms of their option agreements and, therefore, had three months from September 30, 2011 to exercise their vested options before they were canceled.

(2) The intrinsic value of a stock option is the amount by which the market value of the underlying stock, as of the date outstanding or exercised, exceeds the exercise price of the option.

Stock options are granted at the fair market value of one share of common stock on the date of grant and have a term of ten years. Options granted to non-employee directors vest immediately and options granted to officers and other employees vest in increments of 25% on each of the first four anniversary dates of the grant.

The following table summarizes information about options outstanding at December 31, 2011:

| | Stock Options Outstanding and Exercisable | | | |
|---|---|---|---|---|
| Range of Exercise Prices | Number of Options | Weighted Average Remaining Contractual Life (Years) | Weighted Average Exercise Price | Aggregate Intrinsic Value (In Thousands) |
| $9.70 - 10.30 | 501,658 | 1.29 | $9.99 | $1,715 |
| 10.31 - 12.21 | 445,154 | 2.03 | 11.13 | 1,013 |
| 12.22 - 13.40 | 11,573 | 2.94 | 13.10 | 3 |
| 13.41 - 18.45 | 472,306 | 2.87 | 14.12 | — |
| 18.46 - 27.90 | 335,896 | 5.14 | 26.54 | — |
| $9.70 - 27.90 | 1,766,587 | 2.64 | $14.55 | $2,731 |

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Restricted Stock, Performance Units, and Phantom Stock Units

The following table summarizes the restricted stock, performance unit, and phantom stock unit activity in the Stock-based Compensation Plans for the years ended December 31, 2011, 2010, and 2009.

| | Restricted Stock | | | Performance Units | | | Phantom Stock Units | | |
|---|---|---|---|---|---|---|---|---|---|
| | Number of Shares | Weighted Average Grant Date Fair Value | Vest Date Fair Value (In Thousands) | Number of Units | Weighted Average Grant Date Fair Value | Vest Date Fair Value (In Thousands) | Number of Units(3) | Weighted Average Grant Date Fair Value | Vest Date Fair Value (In Thousands) |
| Unvested at January 1, 2009 | 1,490,795 | $52.31 | | — | $— | | 163,954 | $51.10 | |
| Awarded | 839,618 | 18.21 | | — | — | | 360,578 | 18.22 | |
| Vested | (119,145 ) | 45.50 | $ 2,302 | — | — | $ — | | | |