FOREST OIL CORP
Form 10-K
February 24, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

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 ý 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 ý

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 ý 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 ý 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. ý

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 definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2010, the last business day of the registrant's most recently completed second fiscal quarter, was $3,071,420,932 (based on the closing price of such stock).

There were 113,610,016 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 17, 2011.

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, 2010 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, 2010 were approximately 2,244 Bcfe. At December 31, 2010, approximately 81% of Forest's estimated proved oil and gas reserves were in the United States, approximately 17% were in Canada, and approximately 2% were in Italy.

In December 2010, we announced our intention to separate our Canadian operations through an initial public offering ("IPO") of up to 19.9% of the common stock of our wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which will be the holding company of the Canadian operations, followed by a distribution of the remaining shares of Lone Pine held by us to our shareholders. The proceeds from the IPO will be used to repay intercompany debt owed to Forest, and the remainder, if any, for general corporate purposes. We expect the IPO to occur in the first half of 2011 and the spin-off of the remaining shares of Lone Pine to occur approximately four months after the IPO; however, we will retain the right to decide whether to commence the spin-off at our discretion. See Part I, Item 1A "Risk Factors *We may be unable to complete the separation of our Canadian operations as planned or on the terms and manner currently contemplated, and any completed separation may have a negative impact on our business operations, results of operations and financial condition*."

Strategy

Our business strategy is to increase shareholder value by efficiently increasing production and reserves by exploiting our significant and diversified undeveloped acreage positions. We expect to execute this strategy, while managing our debt levels relative to our estimated proved reserves and EBITDA, by keeping our exploration and development expenditures at or near cash flows provided by operating activities. We endeavor to execute this strategy as follows:

Exploit and develop resource plays by applying horizontal drilling. 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 undeveloped oil and gas acreage positions. Our core operational areas, which are discussed in more detail below, have a large number of remaining commodity-diverse drilling locations, providing for what we believe to be repeatable development opportunities. In 2011, we intend to devote approximately 85% of our capital expenditures to our core areas, including approximately 50% in the Texas Panhandle where liquids-rich Granite Wash intervals are targeted.

Enhance returns by focusing on operational control, cost efficiencies and high-margin projects. Our development efforts are focused in areas where we have concentrated land positions, large drilling inventory, and operational control, which allow us to reduce costs. Furthermore, our commodity-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 provide for higher rates of return on invested capital.

Develop, expand, and rationalize our asset base through leasehold and property acquisitions, divestitures, and exploration. We intend to pursue leasehold and property acquisitions to enhance existing business operations in our core areas with a preference for liquids-rich hydrocarbon prospects. We also plan to pursue a measured exploration drilling program in these areas to expand the ultimate scope of commercial development of our asset base. As economic conditions permit, we intend to divest assets that do not fit our primary business strategy, including those without significant development opportunities.

Maintain financial flexibility. We expect to maintain a strong liquidity position to successfully execute our growth strategy through the application of budget controls and prudent financial management. We intend to focus on managing our debt levels relative to our estimated proved reserves and EBITDA.

Core Operational Areas

Forest's core areas consist of a well-balanced portfolio of oil, natural gas, and natural gas liquids properties in North America that have exposure to tight-gas sands and shale plays with multiple stacked-pay opportunities. 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 is able to enhance initial production rates and estimated ultimate recoveries while focusing on reducing drilling costs. Our primary areas of focus in 2011 will be in the Texas Panhandle, the Western Canadian Sedimentary Basin in Alberta and British Columbia, Canada, and the Eagle Ford Shale in South Texas. We expect that these core areas will be primarily responsible for Forest's organic growth in 2011 and will consume the majority of the Company's capital expenditures.

Texas Panhandle Granite Wash

We have approximately 101,000 net acres in the Granite Wash, located in the Texas Panhandle, establishing Forest as one of the top acreage holders in the area. The area provides for excellent horizontal drilling opportunities targeting multiple liquids-rich Granite Wash intervals as well as other multi-pay objectives. Other objectives present in the area are the Douglas, Tonkawa, Cleveland, Atoka, Novi-Lime, and the Morrow. 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. During 2010, Forest tested five prospective intervals in the play, establishing a total of eight intervals as prospective for horizontal development. Forest completed 27 horizontal wells in 2010 that had average 24-hour initial production rates of 26 MMcfe/d, of which approximately 57% of the production was in the form of condensate and natural gas liquids. 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. In 2011, we plan to run a six rig drilling program targeting the Granite Wash and other prospective intervals, investing approximately $300 million primarily for the drilling of approximately 40 gross horizontal operated wells.

Western Canadian Sedimentary Basin

Deep Basin

We have approximately 131,000 net acres in the Deep Basin, located in Alberta and British Columbia, Canada, which primarily includes our interests in the Narraway/Ojay and Wild River fields. The area provides for a rich geologic setting, with a majority of the play containing a minimum of ten different stacked producing intervals. Forest's vertical delineation program has included the drilling of 15 vertical wells in the Narraway/Ojay fields that had average 24-hour initial production rates of 13 MMcfe/d. With a favorable royalty and tax regime, this play provides superior rates of return compared to similar natural gas plays in North America. Utilizing zone-specific production data collected from our vertical well database in the Deep Basin, we commenced the drilling of our first horizontal well in the Narraway/Ojay fields at the end of the fourth quarter of 2010 and intend to complete this well with multi-stage hydraulic fracturing techniques that have been successfully applied in the Granite Wash area since 2009. Although many of the multi-stacked sand intervals in the Deep Basin have not been exploited horizontally, we believe that horizontal drilling will result in improvements in initial production rates and ultimate recoveries. In 2011, we plan to run a two rig drilling program in the Narraway/Ojay fields, investing approximately $82 million primarily for the drilling of approximately 15 gross wells.

Peace River Arch

We have approximately 41,000 net acres in the Peace River Arch, located in Alberta, Canada, which primarily includes our interests in the Evi light oil field. This area provides for a significant development opportunity for premium-priced light oil through shallow horizontal development drilling opportunities. Through December 31, 2010, Forest drilled 25 horizontal wells. Oil production from this field is light sweet crude providing superior rates of return compared to other oil plays in North America. We believe that we can ultimately enhance production rates and recoveries in the Evi field through further development drilling and secondary recovery techniques, such as waterflooding. In 2011, we plan to run a three rig drilling program in the Evi field, investing approximately $93 million primarily for the drilling of approximately 35 gross wells.

South Texas Eagle Ford Shale

We have approximately 105,000 net acres in the Eagle Ford Shale, located in Gonzales, Wilson, Lee, and DeWitt counties in South Texas. The area provides Forest with access to the oil-bearing section of the Eagle Ford and is expected to yield a significant 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 the fourth quarter of 2010 and expanded our initial one rig drilling program to two rigs in the first quarter of 2011. Through Forest's database of vertical penetrations in the Eagle Ford, we believe that we can ultimately increase initial production rates and recoveries through the application of horizontal drilling. In 2011, we plan to run a two rig drilling program in the Eagle Ford, initially investing approximately $50 million primarily for the drilling of approximately eight gross wells during the first half of 2011. Upon success, Forest would consider expanding this program.

East Texas / North Louisiana Haynesville/Bossier Shale

We have approximately 169,000 net acres in the East Texas / North Louisiana area. The area provides for excellent horizontal and vertical drilling opportunities targeting multiple stacked-pay intervals, including the Cotton Valley, Haynesville, Bossier, 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 initial 24-hour production rates of 16 MMcfe/d. In an effort

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to optimize recovery from Haynesville/Bossier Shale wells, Forest instituted a restricted flow rate production program. Under this program, initial production rates from the last six wells were curtailed at 11 to 15 MMcfe/d. Results have indicated that cumulative production from restricted rate wells exceeded the cumulative production from comparable unrestricted wells at a period of approximately 90 days. In 2011, as our acreage base is now generally held-by-production, we plan to redirect our capital spending in this area to more liquids-rich plays in our other core areas until either natural gas prices recover or drilling and completion costs are reduced.

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. The following sets forth our significant acquisitions and divestures over the last several years.

Acquisitions

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 and 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 2009, we sold all of our oil and gas properties located in Permian Basin in West Texas and New Mexico as well as other non-core oil and gas properties in the U.S. and Canada for approximately $1.1 billion in cash. We estimated the proved reserves associated with these properties were 628 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") which were 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.

In March 2006, we completed the spin-off of our offshore Gulf of Mexico operations by means of a special dividend, which consisted of a pro rata spin-off (the "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

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March 3, 2006. We estimated the proved reserves associated with the Spin-off to be 313 Bcfe at the time of closing.

Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2010, based on the Henry Hub price of $4.38 per MMBtu for natural gas and the West Texas Intermediate price of $79.81 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, 2010. See "*Preparation of Reserves Estimates*" below and Note 16 to the Consolidated Financial Statements for additional information regarding our estimated proved reserves.

	Estimated Proved Reserves		
	Natural Gas (MMcf)	Oil and Natural Gas Liquids (MBbls)	Total (MMcfe)[1]
Developed:			
United States	886,644	37,541	1,111,890
Canada	169,292	6,594	208,856
Italy	25,869		25,869
Total developed	1,081,805	44,135	1,346,615
Undeveloped:			
United States	547,087	26,161	704,053
Canada	97,721	11,666	167,717
Italy	25,869		25,869
Total undeveloped	670,677	37,827	897,639
Total estimated proved reserves	1,752,482	81,962	2,244,254

(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 2010, the average of the first-day-of-the-month gas price was $4.38 per Mcf, and the average of the first-day-of-the-month oil price was $79.81 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 18 Mcf per barrel of oil or NGL rather than 6 Mcf per barrel of oil or NGL.

As of December 31, 2010, Forest had estimated proved reserves of 2,244 Bcfe, an increase of 6% compared to 2,121 Bcfe at December 31, 2009. Of that total, 1,816 Bcfe (81%) were in the United States, 377 Bcfe (17%) were in Canada, and 52 Bcfe (2%) were in Italy. During 2010, we added 384 Bcfe of estimated proved reserves through extensions and discoveries primarily driven by our 2010 drilling activity in the Texas Panhandle, North Louisiana, and the Western Canadian Sedimentary Basin, which were offset by property sales of 62 Bcfe and negative revisions of 39 Bcfe.

As of December 31, 2010, proved undeveloped reserves ("PUDs") were estimated to be 898 Bcfe, or 40% of estimated proved reserves, compared to 791 Bcfe, or 37% of estimated proved reserves as of December 31, 2009. The net increase of 106 Bcfe was primarily due to the recording of PUD locations offset to our horizontal and vertical producing wells in the Texas Panhandle and the Deep Basin in Canada. We invested $174 million to convert 91 Bcfe of our December 31, 2009 PUD reserves to proved developed reserves during 2010. We intend to convert the PUDs disclosed as of December 31, 2010 to proved developed reserves within five years of the date they were initially disclosed as PUDs.

The estimated proved reserves presented in the table above were calculated in accordance with the Securities and Exchange Commission's ("SEC") "Modernization of Oil and Gas Reporting" rule, which was first effective for December 31, 2009 reporting. These rules include calculating estimated proved reserves based on the average prices during the twelve-month period prior to the reporting date, with

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such prices determined as the unweighted arithmetic average of the first-day-of-the-month prices for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

The following table sets forth the pre-tax PV-10 (present value of future net revenues before income taxes discounted at 10%) and the standardized measure of discounted future net cash flows of our reserves using (i) the unweighted arithmetic average first-day-of-the-month prices during the twelve-month period prior to December 31, 2010 as required by SEC regulations and (ii) an alternative price using the NYMEX five-year future strip price as of December 31, 2010. Forest presents the pre-tax PV-10 value, which is not a financial measure accepted under Generally Accepted Accounting Principles ("GAAP"), because it is a widely used industry standard which we believe is useful to those who may review this Annual Report on Form 10-K when comparing our asset base and performance to other comparable oil and gas exploration and production companies. The table also reconciles the pre-tax PV-10 value to the standardized measure of discounted future net cash flows by reducing the pre-tax PV-10 values by the estimated income tax effects discounted at 10% per annum.

	Twelve- Month Average Price	Five-Year NYMEX Strip Price
Henry Hub natural gas price	$ 4.38	$ 5.25
West Texas Intermediate oil price	79.81	93.08
Pre-tax PV-10 value (in millions)	$ 3,273	$ 4,435
Less: Income tax effects discounted at 10% per annum (in millions)	554	950
Standardized measure of discounted future net cash flows (in millions)	$ 2,719	$ 3,485

Preparation of Reserves Estimates

Reserve 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 reserve estimates are based on production performance, 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 reserve estimates and significant changes to existing reserves are reviewed and approved by various levels of management, depending on their magnitude. Proved reserve estimates are reviewed and approved by the Senior Vice President, Business Development and 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 reserve estimates or changes made to existing reserves and tests to ensure that they were properly documented and approved.

Forest's Senior Vice President, Business Development and Engineering, Glen Mizenko, has in excess of twenty-five years of experience in oil and gas exploration and production and has held this position since May 2007. Prior to that time, Mr. Mizenko held positions of increasing responsibility at Forest since joining us in early 2001. Prior to joining Forest, Mr. Mizenko held various positions in reservoir engineering, development planning, and operations management with Shell Oil Company, Benton Oil and Gas Company, and British Borneo Oil and Gas PLC. Mr. Mizenko received a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1985 and a Masters of Business Administration from the University of Houston in 1993. He has been a member of the Society of Petroleum Engineers for over twenty-five years.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices or development and production expenses, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve 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 of our year-end proved reserves, discounted at 10% per annum ("NPV"), 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 discounted present value of such fields and a minimum of 80% of the NPV added during the year through discoveries, extensions, and acquisitions. The procedures prohibit exclusions of any fields, or any part of a field, that comprises part of the top 80%. The independent reserve engineers compare their estimates to those prepared by Forest. Our audit guidelines require Forest's internal estimates, which are used for financial reporting purposes, to be within 5% of the independent reserve engineers' quantity estimates on a Company basis and within 10% of the independent reserve engineers' quantity estimates in each country in which proved reserves are recorded. 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, 2010, 2009, and 2008, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the year ended December 31, 2010, DeGolyer and MacNaughton independently audited estimates relating to properties constituting over 87% of our reserves by NPV as of December 31, 2010. 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 35 years of experience in oil and gas reservoir studies and reserves evaluations.

Drilling Activities

The following table summarizes the number of wells drilled during 2010, 2009, and 2008, 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, 2010, we had 14 gross (6 net) wells in progress in the United States and 2 gross (1 net) wells in progress in Canada. During 2010, we drilled a total of

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148 gross (89 net) wells, of which 29 were classified as exploratory and 119 were classified as development. Our 2010 drilling program achieved a 93% success rate.

	Year Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
United States						
Productive	75	38	76	47	550	323
Non-productive(1)	5	4	6	4	15	11
Total	80	42	82	51	565	334
Canada						
Productive	39	27	7	3	64	39
Non-productive(1)						
Total	39	27	7	3	64	39
Total development wells	119	69	89	54	629	373
Exploratory wells:						
United States						
Productive	24	16	23	14	72	54
Non-productive(1)	5	4			3	2
Total	29	20	23	14	75	56
Canada						
Productive			4	2	10	8
Non-productive(1)						
Total			4	2	10	8
Italy						
Productive						
Non-productive(1)			1	1		
Total			1	1		
Total exploratory wells	29	20	28	17	85	64

(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, 2010, all of which are located in the United States, Canada, 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, 2010, Forest owned interests in 347 gross wells containing multiple completions.

United States		Canada		Italy		Total	
Gross	Net	Gross	Net	Gross	Net	Gross	Net

Gas	3,522	2,602	507	338	2	2	4,031	2,942
Oil	361	212	317	258			678	470
Total	3,883	2,814	824	596	2	2	4,709	3,412

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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, 2010. A majority of our developed acreage in the United States and Canada is subject to mortgage liens securing our bank credit facilities. 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, 2010, approximately 19%, 10%, and 5% of our net undeveloped acreage in the United States and Canada was held under leases that will expire in 2011, 2012, and 2013, respectively, if not extended by exploration or production activities. Approximately 40% of the acres expiring in 2011 are held under leases that can be extended, at our option, for another two years.

	Developed Acreage		**Undeveloped Acreage**	
Location	**Gross**	**Net**	**Gross**	**Net**
United States:				
Western[1]	252,679	119,918	228,340	124,033
Eastern[2]	226,608	164,444	106,237	66,844
Southern[3]	174,781	109,210	118,747	109,120
	654,068	393,572	453,324	299,997
Canada[4]	218,264	148,274	888,987	642,650
International:				
South Africa[5]			2,771,695	1,474,542
Italy	2,500	2,250	288,543	231,457
	2,500	2,250	3,060,238	1,705,999
Total	874,832	544,096	4,402,549	2,648,646

(1) The Western Business Unit's acreage is primarily located in the Texas Panhandle and the Uintah field in Utah.

(2) The Eastern Business Unit's acreage is primarily located in the East Texas / North Louisiana area and the Arkoma Basin in Arkansas.

(3) The Southern Business Unit's acreage is primarily located in South Texas, including approximately 105,000 net acres prospective for the Eagle Ford shale in Gonzales, Wilson, Lee, and DeWitt counties.

(4) The Canadian Business Unit's acreage is primarily located in the Deep Basin area in Alberta and British Columbia, the Peace River Arch area in Alberta, and 274,000 net acres in Quebec prospective for the Utica Shale.

(5) Forest 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.

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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, 2010, 2009, and 2008 by geographical area. 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.

	United States			Canada			Total Company		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Natural Gas:									
Production volumes (MMcf)	101,346	116,029	118,120	22,436	23,248	23,313	123,782	139,277	141,433
Average sales price (per Mcf)	$ 3.99	$ 3.33	$ 7.54	$ 3.71	$ 3.15	$ 6.98	$ 3.94	$ 3.30	$ 7.45
Liquids:									
Oil and condensate:									
Production volumes (MBbls)	2,357	3,397	3,778	828	626	802	3,185	4,023	4,580
Average sales price (per Bbl)	$ 76.08	$ 56.87	$ 96.85	$ 67.51	$ 51.14	$ 86.68	$ 73.85	$ 55.98	$ 95.07
Natural gas liquids:									
Production volumes (MBbls)	3,589	3,012	3,151	134	230	300	3,723	3,242	3,451
Average sales price (per Bbl)	$ 34.54	$ 25.17	$ 44.54	$ 51.68	$ 30.82	$ 60.71	$ 35.16	$ 25.57	$ 45.94
Total liquids:									
Production volumes (MBbls)	5,946	6,409	6,929	962	856	1,102	6,908	7,265	8,031
Average sales price (per Bbl)	$ 51.01	$ 41.97	$ 73.06	$ 65.30	$ 45.68	$ 79.61	$ 53.00	$ 42.41	$ 73.96
Total production volumes (MMcfe)	**137,022**	**154,483**	**159,694**	**28,208**	**28,384**	**29,925**	**165,230**	**182,867**	**189,619**
Average sales price (per Mcfe)	$ **5.16**	**$ 4.24**	**$ 8.75**	**$ 5.18**	**$ 3.95**	**$ 8.37**	**$ 5.17**	**$ 4.20**	**$ 8.69**
Production costs (per Mcfe):									
Lease operating expenses	$ .67	$ .77	$ .83	$ .91	$ .97	$ 1.21	$ .71	$ .80	$ .89
Transportation and processing costs	.10	.08	.06	.38	.28	.32	.15	.11	.10
Production costs excluding production and property taxes (per Mcfe)	.77	.86	.89	1.29	1.25	1.53	.86	.92	.99
Production and property taxes	.32	.26	.49	.09	.10	.12	.28	.23	.43
Total production costs (per Mcfe)	**$ 1.09**	**$ 1.12**	**$ 1.38**	**$ 1.38**	**$ 1.35**	**$ 1.65**	**$ 1.14**	**$ 1.15**	**$ 1.42**

Marketing and Delivery Commitments

Our natural gas production is generally sold on a month-to-month basis in the spot market, priced in reference to published indices. Our oil production is generally sold under short-term contracts at prices based upon refinery postings and is typically sold at 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. As of February 17, 2011, we have a delivery commitment of approximately 21 Bbtu/d of natural gas, which provides for a price equal to NYMEX Henry Hub less $1.49 to a buyer through October 31, 2014, unless the Henry Hub price exceeds $6.50 per MMBtu, at which point we share the amount of the excess equally with the buyer. Approximately 90% of our current natural gas production in Alberta and British Columbia is available to be used as source gas for this delivery commitment. Based on our estimated proved reserves as of December 31, 2010, approximately 72 MMcfe/d, 64 MMcfe/d, and 74 MMcfe/d will be available as source gas from these fields in 2011, 2012, and 2013, respectively.

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. See Part I, Item 1A "Risk Factors *Competition within our industry is intense and may adversely affect our operations"* below.

Regulation

Our oil and gas operations are subject to various U.S. federal, state, and local laws and regulations, Canadian federal, provincial, 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 and/or pending legislative or regulatory changes include the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, taxation, and the use of derivative hedging instruments. 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, Canada, 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. We may not be able to recover some or any of these costs from insurance.

United States

Various aspects of our oil and natural gas operations are subject to regulation by state and federal agencies. Each of the jurisdictions in which we own or operate producing crude oil and natural gas properties has adopted laws regulating the exploration for and production of crude oil and natural gas, including laws requiring permits for the drilling of wells, imposing bonding requirements in order to drill or operate wells, and providing authority for regulation relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, 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

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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.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amended the Natural Gas Act ("NGA") to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as Forest, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission ("FERC"), in contravention of rules prescribed by the FERC. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1 million per day per violation. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC's enforcement authority. We do not believe these rules affect us any differently than other producers of natural gas.

In December 2007, the FERC issued rules requiring that any market participant, including a producer such as Forest, that engages in physical sales for resale or purchases for resale of natural gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report such sales or purchases to the FERC, beginning on May 1, 2009. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. On September 18, 2008 the FERC issued its order on rehearing, which largely approved the existing rules, except the FERC exempted from the reporting requirement certain types of purchases and sales, including purchases and sales of unprocessed gas and bundled sales of gas made pursuant to state regulated retail tariffs. Also, the FERC clarified that other end use purchases and sales are not exempt from the reporting requirements.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was enacted which, among other things, imposes new 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 FERC, and the courts. For instance, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations an important process used in the completion of our oil and gas wells to regulation under the act. If adopted, this legislation could establish an additional level of regulation, and impose additional costs, on our operations. 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.

Canada

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada in certain circumstances. Regulatory requirements also exist related to licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, and conservation matters. We do not expect that any of these controls and regulations will affect us in a manner significantly different from other oil and natural gas companies in Canada.

The provinces in which we operate have legislation and regulation governing land tenure, royalties, production rates and taxes, environmental protection, and other matters under their respective jurisdictions. The royalty regime in the provinces where we operate is a significant factor in the profitability of our production. Crown royalties are determined by government regulation and are typically calculated as a percentage of the value of production. The value of the production and the rate of royalties payable depend on prescribed reference prices, well productivity, geographical location, and the type of product produced. Any royalties payable on production from privately owned lands are determined by negotiations between us and the landowners.

The majority of our Canadian operations are located in the Province of Alberta. The Alberta Government implemented a new oil and gas royalty framework effective January 2009. The new royalty framework (since named the Alberta Royalty Framework, or ARF) established new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the ARF, as further amended, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependent on the market price and production volumes. Royalty rates for conventional oil range from 0% to 40%. Natural gas royalty rates range from 5% to 36%.

In November 2008, the Alberta Government announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 meters and 3,500 meters (or 3,281 feet and 11,483 feet), for which drilling begins between November 19, 2008 and December 31, 2013 (since changed to December 31, 2010), would have a one-time option of selecting transitional royalty rates or ARF rates. The transition option provides for lower royalties in the initial years of a well's life and at some commodity price points. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. The election for transition royalty rates for wells brought on production after June 30, 2009, must be made before the end of the first month in which production begins. Re-entry wells that are given a new drill date are also eligible for the transition option. All wells using the transitional royalty rates will revert to ARF rates on January 1, 2014.

Our drilling programs in Alberta have included, and in the future may include, deeper wells. On January 1, 2009, two new royalty programs impacting deep drilling activities went into effect. The Deep Oil Exploration Program, or DOEP, and the Natural Gas Deep Drilling Program, or NGDDP, provide upfront royalty adjustments to qualifying new wells. To qualify for royalty adjustments under the DOEP, exploration wells must have a true vertical depth greater than 2,000 meters (6,562 feet) and drilling must commence on or after January 1, 2009. Oil wells in this category qualify for a royalty exemption on either the first $1 million (Canadian dollars) of royalty or the first 12 months of production. The DOEP is a five year program. No wells drilled after December 31, 2013 will qualify for benefits under the DOEP, and no royalty adjustments will be granted under the DOEP after December 31, 2018. The

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NGDDP, as revised effective May 1, 2010, applies to qualifying exploration and development gas wells producing at a true vertical depth greater than 2,000 meters (6,562 feet) for which drilling commenced on or after May 1, 2010. The NGDDP provides for an escalating royalty credit in line with progressively deeper wells from $625 (Canadian dollars) per meter ($191 (Canadian dollars) per foot) to a maximum of $3,750 (Canadian dollars) per meter ($1,143 (Canadian dollars) per foot). A minimum 5% royalty will apply to these gas wells. The majority of our drilling activities and wells in Alberta will be subject to the new royalty framework or, at our election, the transitional rules. As a result, wells that we drill in the future may be subject to the new higher royalty rates, which may be partially offset by credits for deep wells, while our existing production base will be subject to lower royalty rates.

On March 3, 2009, the Alberta Government announced a new incentive program, which included a Drilling Royalty Credit, or DRC, for new oil, natural gas and non-project oil sands wells for which drilling commenced and finished between April 1, 2009 and March 31, 2011, and a New Well Royalty Rate, or NWRR, for wells that began producing between April 1, 2009 and March 31, 2010. The DRC provides for a royalty credit of up to $200 (Canadian) per meter ($61 (Canadian) per foot) drilled in respect of qualifying wells with certain annual limitations on the amount of annual credits received directly from the Alberta Government. The NWRR provides for a maximum 5% royalty rate for the first twelve months of production to a maximum of 50,000 barrels of oil or 500 MMcf of natural gas.

On March 11, 2010, the Alberta Government announced its intention to adjust the royalty framework established in January 2009, which adjustments became effective January 1, 2011 and reduced the maximum ARF royalty rates to 40% for conventional oil and to 36% for natural gas (previously 50% for both conventional oil and natural gas). In addition, the Alberta Government made the incentive 5% royalty rate on new natural gas and conventional oil wells under the NWRR a permanent feature of the royalty system subject to the same 12-month time and maximum volume limits. The transitional royalty framework announced in November 2008 was also amended. Transitional royalty rates for qualifying wells will continue until December 31, 2013 as originally announced, but the one-time option of selecting transitional royalty rates ended on December 31, 2010 and, effective January 1, 2011, no new wells are allowed to select transitional royalty rates.

On May 27, 2010, the Alberta Government announced a number of additional programs for qualifying wells coming on production after May 1, 2010. One such program, the Shale Gas New Well Royalty Rate, extended the 5% NWRR on qualifying shale gas wells from 12 months to 36 months and removed the 500 MMcf volume limit. Similarly, the Coalbed Methane New Royalty Rate extended the 5% NWRR on qualifying coalbed methane wells from 12 months to 36 months and increased the 500 MMcf volume limit to 750 MMcf. The Horizontal Gas New Royalty Rate extended the 5% NWRR on qualifying horizontal gas wells from 12 months to 18 months. Finally, the Horizontal Oil New Royalty Rate extended the 5% NWRR on qualifying horizontal oil wells from 12 months to a minimum of 18 months and increased producing time and volume limits according to the measured depth of the well's qualifying interval to a maximum of 48 months or 100,000 bbls, respectively.

Environmental

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 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.

Canada and Italy are signatories to the United Nations Framework Convention on Climate Change and have ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"). At the Copenhagen Conference in 2009, government leaders and representatives from approximately 170 countries met to negotiate a successor to the Kyoto Protocol, which expires in 2012. The primary result of the Copenhagen Conference was the Copenhagen Accord, which is not a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the Kyoto Protocol's commitment to reducing GHG emissions and promises funding to help developing countries mitigate and adapt to climate change. Canada has committed under the Copenhagen Accord to reducing its GHG emissions by 17% from 2005 levels by 2020, but the Copenhagen Accord does not establish binding GHG emissions reduction targets. The United States has not ratified the Kyoto Protocol or the Copenhagen Accord.

The Canadian federal government previously released the *Regulatory Framework for Air Emissions*, updated March 10, 2008 by *Turning the Corner: Regulatory Framework for Industrial Greenhouse Emissions* (collectively, the "Regulatory Framework") for regulating GHG emissions and in doing so proposed mandatory emissions intensity reduction obligations on a sector by sector basis. Regulations to implement the Regulatory Framework had been expected, but the federal government has delayed their release, and potential federal requirements in respect of GHG emissions are unclear. On January 30, 2010, the Canadian federal government announced its new GHG emissions reduction of 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020. In 2009, the Canadian federal government announced its commitment to work with the provincial governments to implement a North America-wide cap-and-trade system for GHG emissions, in cooperation with the United States. It is uncertain whether either federal GHG regulations or an integrated North American cap-and-trade system will be implemented, or what obligations might be imposed under any such systems.

Additionally, GHG regulation takes place at the provincial and municipal levels in Canada. For example, Alberta introduced the Climate Change and Emissions Management Act, which provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulation, the Specified Gas Emitters Regulation, applies to facilities in Alberta that have produced 100,000 or more tons of GHG emissions in 2003 or any subsequent year, and requires mandatory emissions reductions through the use of emissions intensity targets. A company can meet the applicable emissions limits by making emissions intensity improvements at facilities, offsetting GHG emissions by purchasing offset credits or emission performance credits in the open market, or acquiring "fund credits" by making payments of $15 (Canadian dollars) per ton of GHG emissions to the Alberta Climate Change and Management Fund. The Specified Gas Reporting Regulation also imposes GHG

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emissions reporting requirements. Alberta Environment has publicly announced its intention to lower this reporting threshold for facilities to 50,000 tons of GHG emissions annually. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations in permits and under other environmental regulations. The Province of Alberta announced in January 2008 a new climate change plan setting out a goal of achieving a 14% absolute reduction in GHG emissions below 2005 levels in the province by 2050. The Canadian federal government currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. The direct and indirect costs of these regulations may adversely affect our operations and financial results.

Nearly half of the states in the U.S., either individually or through multi-state initiatives, already have begun implementing legal measures to reduce emissions of 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 United States Environmental Protection Agency ("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 (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 CO2 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 percent of the total GHG emissions from the U.S. petroleum and natural gas industries, including all of Forest's facilities. 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 to be followed in order to comply with environmental laws and regulations in the United States, Canada, 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.

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Employees

As of December 31, 2010, we had 681 employees. None of our employees is currently represented by a union for collective bargaining purposes.

Geographical Data

Forest operates in one industry segment. For information relating to our geographical operating segments, see Note 14 to the Consolidated Financial Statements of this Annual Report on Form 10-K.

Offices

Our corporate office is located in leased space at 707 17th Street, Denver, Colorado 80202. We maintain offices in Houston, Texas and Calgary, Alberta, Canada, 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 facilities, 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 or British Thermal Unit. The amount of heat necessary to raise the temperature of one pound of water one degree Fahrenheit.

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

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

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

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

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

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

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well or a service well.

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

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

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

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

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

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

Liquids. Describes oil, condensate, and natural gas liquids.

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

Mcf. Thousand cubic feet of natural gas.

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

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

MMcf. Million cubic feet of natural gas.

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

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.

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NYMEX. New York Mercantile Exchange.

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

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

Proved reserves. Quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Existing economic conditions include prices that are the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves. Estimated proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recovery to occur.

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

Standardized measure 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

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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," variations of such words, and similar expressions identify forward-looking statements. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events.

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;
- our outlook on oil and 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 and forecasts 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 can be affected by inaccurate assumptions and 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" and "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.

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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.

We may be unable to complete the separation of our Canadian operations as planned or on the terms and manner currently contemplated, and any completed separation may have a negative impact on our business operations, results of operations and financial condition.

In December 2010, we announced a strategy to separate our Canadian operations through an initial public offering (the "IPO") of up to 19.9% of the common stock of our wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which will be the holding company of the Canadian operations, followed by a distribution of the remaining shares of Lone Pine held by us to our shareholders. The completion of the IPO and subsequent spin-off of Lone Pine are subject to various risks, including market conditions, which are beyond Forest's control. These risks could have a negative impact on our business operations, results of operations, or financial condition, including:

- the distraction of management and disruption of operations;
- the process of completing the separation may be time consuming and expensive and may result in the loss of business opportunities; and
- our inability to achieve the expected benefits of the IPO, the spin-off, or both.

It is possible that the IPO or the spin-off, or both, will not be completed. Furthermore, if the IPO is completed but the spin-off is not, our securities and other compliance obligations, including associated costs, will increase significantly as Lone Pine will have independent reporting and corporate governance requirements, but will remain a part of our consolidated group.

Our announcement of Lone Pine's initial public offering did not, and this report does not, constitute an offer to sell or the solicitation of an offer to buy any securities. Any offers, solicitations of offers to buy, or any sales of securities of Lone Pine will be made only in accordance with the registration requirements of the Securities Act or an exemption therefrom.

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

Our financial condition, results of operations, and future rate of growth depend upon the prices that we receive for our oil and natural gas. Prices also affect our cash flow available for capital expenditures and our ability to access funds under our bank credit facilities and through the capital markets. The amount available for borrowing under our bank credit facilities is subject to a global

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borrowing base, which is determined by our lenders taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. Declines in oil and natural gas prices have in the past adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our global borrowing base. Future commodity price declines may have similar adverse effects on our reserves and global borrowing base. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources *Bank Credit Facilities*," for more details. Further, because we have elected to use the full-cost accounting method, each quarter we must perform a "ceiling test" that is impacted by declining prices. Significant price declines could cause us to take one or more ceiling test write-downs, which would be reflected as non-cash charges against current earnings. See " *Lower oil and gas prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values*."

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

The markets for oil and natural gas have been volatile historically and are likely to remain volatile in the future. Oil and natural gas spot prices are significantly lower than their historical, or near historical, highs reached in 2008, and prices may continue to fluctuate widely in the future. The prices we receive for our oil and natural gas depend upon factors beyond our control, including among others:

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

These factors make it very difficult to predict future commodity price movements with any certainty. We sell the majority of our oil and natural gas production at current prices rather than through fixed-price contracts. However, we do enter into derivative instruments to reduce our exposure to fluctuations in oil and natural gas prices. See " *Our use of hedging transactions could result in financial losses or reduce our income*." Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Approximately 78% of our estimated proved reserves at December 31, 2010 were natural gas, and, as a result, our financial results will be more sensitive to fluctuations in natural gas prices.

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

We require substantial capital expenditures to conduct our exploration, development, and production operations, engage in acquisition activities, and replace our production. Historically, we have funded our capital expenditures through a combination of our cash flows from operations, our bank credit facilities, and debt and equity issuances. We also engage in asset sale transactions to fund capital expenditures when market conditions permit us to complete transactions on terms we find acceptable. For any large acquisitions or other exceptional expenditures, we expect we would need to access the public or private capital markets or complete additional asset sales. If our revenues and cash flows decrease in the future as a result of a decline in commodity prices, however, and we are unable to obtain additional debt or equity financing in the private or public capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to replace our reserves or maintain our production levels. In addition, as noted above, the amount available for borrowing under our bank credit facilities is adjusted based on periodic determinations of our estimated proved reserves, which may be reduced in the event of commodity price declines. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources *Bank Credit Facilities*," for more details.

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

- the value and performance of our debt and equity securities;
- the credit ratings assigned to our debt by independent rating agencies;
- domestic and global economic conditions; and
- conditions in the domestic and global financial markets.

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

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

We have a substantial amount of indebtedness, and we may incur more debt in the future. This indebtedness 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 pay principal and interest on the debt, which will reduce the amount available to fund working capital, capital expenditures, and other general corporate purposes;
- 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 due to changes in our debt level or our financial condition;
- limit our access to the capital markets;

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- increase our borrowing costs, and impact the terms, conditions, and restrictions contained in our debt agreements, including the addition of more restrictive covenants;
- limit our flexibility in planning for and reacting to changes in our business as covenants and restrictions contained in our existing and possible future debt arrangements may require that we meet certain financial tests and place restrictions on the incurrence of additional indebtedness;
- place us at a disadvantage compared to similar companies in our industry that have less debt; and
- make us more vulnerable to economic downturns and adverse developments in our business.

Our credit and debt agreements contain various restrictive covenants. A failure on our part to comply with the financial and other restrictive covenants contained in our bank credit facilities and the indentures pertaining to our outstanding senior notes could result in a default under these agreements. Any default under our bank credit facilities or indentures could adversely affect our business and our financial condition and results of operations, and would impact our ability to obtain financing in the future. In addition, the global borrowing base included in our bank credit facilities is subject to periodic redetermination by our lenders. A lowering of our global borrowing base could require us to repay indebtedness in excess of the borrowing base. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources *Bank Credit Facilities*."

A higher level of debt will increase the risk that we may default on our financial obligations. Our ability to meet our debt obligations and other expenses will depend on our future performance. Our future performance will be affected by oil and natural gas prices, financial, business, domestic and global economic conditions, governmental regulations and environmental regulations, and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance the debt, sell assets, or sell shares of our stock on terms that we do not find attractive, if it can be done at all.

A portion of our borrowings from time to time may be at variable interest rates, making us vulnerable to increases in interest rates.

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

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

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

Our hedging transactions will impact our earnings in various ways. Due to the volatility of oil and natural gas prices, we may be required to recognize mark-to-market gains and losses on derivative instruments as the estimated fair value of our commodity derivative instruments is subject to significant

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fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period to period estimates and will be a function of the actual price of the commodities on the settlement date of the derivative instrument. We expect that commodity prices will continue to fluctuate in the future and, as a result, our periodic financial results will continue to be subject to fluctuations related to our derivative instruments.

Currently, all of our outstanding commodity derivative instruments are with certain lenders or affiliates of the lenders under our bank credit facilities. We generally do not enter into derivative instruments that require us to provide margin to counterparties. Our obligations under our existing derivative instruments with our lenders are secured by the security documents executed by the parties under our bank credit facilities. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations *Realized and Unrealized Gains and Losses on Derivative Instruments*" and "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources" as well as Item 7A, "Quantitative and Qualitative Disclosure about Market Risk Commodity Price Risk" for further details about our hedging activities.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of legislation.

The Fiscal Year 2012 U.S. Budget proposed by the President recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies, and legislation has been introduced in Congress that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of such U.S. federal income tax incentives. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could impact the rate at which we develop our oil and gas properties.

The enactment of financial reform legislation could have an adverse impact on our ability to hedge risks associated with our business.

On July 21, 2010, the Dodd-Frank Act was enacted, which will, among other things, impose new requirements and oversight on derivatives transactions, including new clearing and margin 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. The new requirements, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in oil and gas commodity prices and interest rates, and could have an adverse effect on our ability to effectively hedge risks associated with our business.

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

We use the full cost method of accounting to report our oil and gas operations. Under this method, we capitalize the cost to acquire, explore for, and develop oil and gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and gas properties may not exceed a "ceiling limit," which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling test write-down." Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write-down would not impact cash flow from operating activities, but it would reduce our shareholders' equity. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies, Estimates, Judgments, and Assumptions *Full Cost Method of Accounting*" below, for further details.

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

We also assess the carrying amount of goodwill in the second quarter of each year and at other periods when events occur that may indicate an impairment exists. These events include, for example, a significant decline in oil and gas prices or a decline in our market capitalization.

The risk that we will be required to write-down the carrying value of our oil and gas properties, our unproved properties, or goodwill increases when oil and gas prices are low. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. For example, we recorded non-cash ceiling test write-downs of approximately $2.4 billion in 2008 and $1.6 billion in 2009. These write-downs were reflected as charges to net earnings. Additional write-downs of our full cost pools may be required if oil and natural gas prices decline further, unproved property values decrease, estimated proved reserve volumes are revised downward or costs incurred in exploration, development, or acquisition activities in the respective full cost pools exceed the discounted future net cash flows from the additional reserves, if any, attributable to each of the cost pools.

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

The proved oil and gas reserve 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 audited by DeGolyer and MacNaughton, an independent petroleum engineering firm. Estimating quantities of proved oil and natural gas reserves is a subjective, complex process and depends on a number of variable factors and assumptions. To prepare estimates of economically recoverable oil and natural gas reserves and future net cash flows:

- we analyze historical production from the area and compare it to production rates from other producing areas;

- we analyze available technical data, including geological, geophysical, production, and engineering data, and the extent, quality, and reliability of this data can vary; and

- we must make various economic assumptions, including assumptions about oil and natural gas prices, drilling, operating, and production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the availability of funds.

As a result, these estimates are inherently imprecise. Ultimately, actual production, revenues, taxes, expenses, and expenditures relating to our reserves will vary from our estimates. Any significant inaccuracies in our assumptions or changes in operating conditions could cause the estimated quantities and net present value of the reserves contained in this Annual Report on Form 10-K to be significantly different from the actual quantities and net present value of our reserves. In addition, we may adjust our estimates of proved reserves to reflect production history, actual results, prevailing commodity prices, and other factors, many of which are beyond our control.

Further, you should not assume that any present value of future net cash flows from our estimated proved reserves contained in this Annual Report on Form 10-K represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on first-day-of-month average oil and natural gas prices for the twelve-month period preceding the estimate and on costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations and, or taxes. At December 31, 2010, approximately 40% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserve 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. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

Our failure to replace our reserves could result in a material decline in our reserves and production, which could adversely affect our financial condition.

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

Drilling is a high-risk activity and may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The seismic data and other technologies that we use when drilling wells do not allow us to conclusively

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determine prior to drilling a well whether oil or natural gas is present or can be produced economically. As a result, we may drill new wells or participate in new wells that are dry wells or are productive but not commercially productive and, as a result, we may not recover all or any portion of our investment in the wells we drill or in which we participate.

The costs and expenses of drilling, completing, and operating wells are often uncertain. The presence of unanticipated pressures or irregularities in formations, miscalculations, or accidents may cause our drilling costs to be significantly higher than expected or cause our drilling activities to be unsuccessful or result in the total loss of our investment. Also, our drilling operations may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control, including, among others:

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

We conduct a portion of our drilling activities through a wholly-owned drilling subsidiary that 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 the factors described above, and other risks associated with conducting drilling activities. Among other things, these risks include the risk of natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases, any of which could result in substantial losses, personal injuries or loss of life, severe damage to or destruction of property, natural resources, and equipment, extensive pollution or other environmental damage, clean-up responsibilities, regulatory investigations, and administrative, civil, and criminal penalties, and injunctions resulting in the suspension of our operations. If any of these risks occur, we could sustain substantial losses.

Competition within our industry is intense and may adversely affect our operations.

We operate in a highly competitive environment. We compete with major and independent oil and gas companies in acquiring desirable oil and gas properties and in obtaining the equipment and labor required to develop and operate such properties. We also compete with major and independent oil and gas companies in the marketing and sale of oil and natural gas. Many of these competitors are larger, including some of the fully integrated energy companies, have financial, staff, and other resources substantially greater than ours, may be less leveraged than we are and have a lower cost of capital. As a result, these companies may have greater access to capital and may be able to pay more for development prospects and producing properties, or evaluate and bid for a greater number of properties and prospects than our financial and staffing resources permit. Also, from time to time, we have to compete with financial investors in the property acquisition market, including private equity sponsors with more funds and access to additional liquidity. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and

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evaluate properties, available funds, and internal standards for minimum projected return on investment. In addition, while costs for equipment, service, and labor in the industry as well as the cost of properties available for acquisition tend to fluctuate with oil and gas prices, these costs often do not decrease proportionately to, or their decreases lag behind, decreases in commodity prices. This disconnect can negatively impact our cash flows and may put us at a competitive disadvantage with respect to companies that have greater financial and operational resources. In addition, oil and gas producers are increasingly facing competition from providers of non-fossil energy, and government policy may favor those competitors in the future. Many of these competitors have financial and other resources substantially greater than ours. We can give no assurance that we will be able to compete effectively in the future and that our financial condition and results of operations will not suffer as a result.

Our growth may depend partly on our ability to acquire oil and gas properties on a profitable basis.

Acquisition of producing oil and gas properties has historically been a key element of maintaining and growing our reserves and production. Competition for these assets has been and will continue to be intense. The success of any acquisition will depend on a number of factors, including, among others:

- the acquisition price;
- future oil and gas prices;
- our ability to reasonably estimate or assess the recoverable volumes of reserves;
- rates of future production and future net revenues attainable from reserves;
- future operating and capital costs;
- our ability to promptly integrate the new operations with existing operations;
- results of future exploitation, exploration, and development activities on the acquired properties; and
- future abandonment and possible future environmental liabilities.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results from an acquisition may vary substantially from those assumed in the purchase analysis, and acquired properties may not produce as expected; or there may be conditions that subject us to increased costs and liabilities, including environmental liabilities. See " *We require substantial capital expenditures to conduct our operations, engage in acquisition activities, and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy*," for a discussion of the impact of the financial market conditions on our access to financing.

Our international operations may be adversely affected by currency fluctuations and economic and political developments.

We currently have oil and gas properties and operations in Canada, Italy, and South Africa. As a result, we are exposed to the risks of international operations, including political and economic developments, royalty and tax increases, changes in laws or policies affecting our exploration and development activities, and currency exchange risks, as well as changes in the policies of the United States affecting trade, taxation, and investment in other countries.

We have significant operations in Canada. The revenues and expenses of these operations are denominated in Canadian dollars. As a result, the profitability of our Canadian operations is subject to the risk of fluctuation in the exchange rates between the U.S. dollar and Canadian dollar. In addition,

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our Canadian operations may be adversely affected by regulatory developments. For instance, Canadian federal and provincial governments have announced initiatives to reduce greenhouse gas emissions, and regulations to implement such initiatives could potentially impact our operations. See Part I, "Business-Regulation-*Canada*" and "Business-Regulation-*Environmental*" for more detail on the Canadian regulatory framework.

In addition, our oil and gas exploration activities in Italy and South Africa may be adversely affected by political, economic, and regulatory developments, changes in the local royalty and tax regimes, and currency fluctuations.

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

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

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

Our oil and gas operations are subject to various U.S. federal, state, and local laws and regulations, Canadian federal, provincial, and local laws and regulations, and local and federal laws and regulations in Italy and South Africa. These laws and regulations may be changed in response to economic or political conditions. There can be no assurance that present or future regulations will not adversely affect our business and operations.

Many of the laws and regulations to which our operations are subject include those relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and the clean-up of contaminated sites. 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, environmental laws and regulations. Such laws and regulations not only expose us to liability for our own activities, but may also expose us to liability for the conduct of others or for actions by us that were in compliance with all applicable laws at the time those actions were taken. In addition, we could incur substantial expenditures complying with environmental laws and regulations, including future environmental laws and regulations which may be more stringent, for example, the regulation of GHG emissions under new federal legislation, the federal Clean Air Act, or state or regional regulatory programs. Regulation of GHG emissions by Congress, the EPA, or various other legislative or regulatory bodies in the United States, Canada or Italy could have an adverse effect on our operations and demand for the oil and natural gas that we produce. See Part I, Item 1, "Business Regulation" for more detail on both current and potential governmental regulation.

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

The marketability of our production depends in part upon the availability, proximity, and capacity of pipelines, natural gas gathering systems, and processing facilities. Any significant change in market factors affecting these infrastructure facilities, as well as delays in the construction of new infrastructure facilities, could harm our business. We deliver 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 or access to gathering systems that impact a substantial amount of our production, it could have an adverse impact on our cash flow.

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

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

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 the "Spurr 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. In addition, PERL has asserted during its bankruptcy case that the Alaska Assets were worth less than what PERL paid for them in August 2007, and that Forest may face liability under creditors' rights laws or other laws in connection with the transaction. Forest disagrees with both the working interest owners' assertion and PERL's assertion and, to the extent necessary, will vigorously oppose any efforts to hold Forest liable for PERL's unsatisfied obligations or for the sale of the Alaska Assets to PERL. We cannot predict, however, whether we would be successful in avoiding all such liabilities.

Our Restated Certificate of Incorporation and Bylaws have provisions that discourage corporate takeovers.

Certain provisions of our Restated Certificate of Incorporation and Bylaws and provisions of the New York Business Corporation Law may have the effect of delaying or preventing a change in control. Our directors are elected to staggered terms. Also, our Restated Certificate of Incorporation authorizes our board of directors to issue preferred stock without shareholder approval and to set the rights, preferences, and other designations, including voting rights of those shares as the board may determine. Additional provisions include restrictions on business combinations, the availability of authorized but unissued common stock, and notice requirements for shareholder proposals and director nominations. Also, our board of directors has adopted a shareholder rights plan. If activated, this plan would cause extreme dilution to any person or group that attempts to acquire a significant interest in Forest without advance approval of our board of directors. The provisions contained in our Bylaws and Restated Certificate of Incorporation, alone or in combination with each other and with the shareholder rights plan, may discourage transactions involving actual or potential changes of control.

Item 1B. Unresolved Staff Comments.

As of December 31, 2010, we did not have any SEC staff comments that have been unresolved for more than 180 days.

Item 2. Properties.

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

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, Unocal 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. Unocal 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. 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. Removed and Reserved.

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Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of February 17, 2011.

Name	Age	Years with Forest	Office[1]
H. Craig Clark	54	10	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	36	10	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	55	7	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	60	22	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.
Leonard C. Gurule	54	8	Senior Vice President, Western Region since March 2009. He joined Forest as Senior Vice President, Alaska, in September 2003. Mr. Gurule served as Senior Vice President following the sale of our Alaska business in August 2007, while providing project oversight for Italy. From 1987 to 2000, he served in various capacities at Atlantic Richfield Co. Before joining Forest, Mr. Gurule served on the boards of several local community and non-profit organizations and managed his own investment portfolio.
Cyrus D. Marter IV	47	9	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	48	10	Senior Vice President, Business Development and Engineering since May 2007. 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. 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.

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Name	Age	Years with Forest	Office[(1)]
Victor A. Wind	37	6	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.
Mark E. Bush	50	14	Vice President, Eastern Region since April 2007. Mr. Bush joined Forest in June 1997 as Production Engineer in the Gulf of Mexico Region and was subsequently promoted to Offshore Production Engineering Manager and Production Engineering Manager, both in the Gulf Coast Region and its successor, the Eastern Region. Prior to joining Forest Oil, he worked for Oryx Energy Company (formerly Sun E&P) in various production engineering assignments in the Gulf of Mexico and South Texas.
Ronald C. Nutt	53	4	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 meetings 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 17, 2011, our Common Stock was held by 690 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 for each quarterly period in 2009 and 2010. There were no cash dividends declared on the Common Stock in 2009 or 2010. On February 17, 2011, the closing price of Forest Common Stock was $39.65.

		Common Stock	
		High	Low
2009	First Quarter	$ 21.79	$ 10.33
	Second Quarter	22.26	12.45
	Third Quarter	20.17	12.01
	Fourth Quarter	24.99	17.15
2010	First Quarter	$ 30.08	$ 22.61
	Second Quarter	32.81	22.85
	Third Quarter	31.89	24.83
	Fourth Quarter	39.32	29.69

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 8% senior notes due 2011, Forest's $8^1/_2$% senior notes due 2014, and Forest's $7^1/_4$% senior notes due 2019, and (iv) Forest's United States and Canadian bank credit facilities dated as of June 6, 2007, as amended. The provisions in the indentures pertaining to these senior notes and in the bank credit facilities 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. In December 2010, Forest announced a strategy 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 will be the holding company of the Canadian operations, followed by a distribution of the remaining shares of Lone Pine held by Forest to its shareholders, with such distribution occurring at Forest's discretion. 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 and our ability to pay dividends on our Common Stock, see Notes 4 and 6 to the Consolidated Financial Statements. See Part I, Item 1A "Risk Factors *We may be unable to complete the separation of our Canadian operations as planned or on the terms and manner currently contemplated, and any completed separation may have a negative impact on our business operations, results of operations and financial condition.*"

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Unregistered Sales of Equity Securities

We did not make any sales of unregistered equity securities during 2010.

Issuer Purchases of Equity Securities

The table below sets forth information regarding repurchases of our Common Stock during the quarter ended December 31, 2010. 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 2010	3,609	$ 31.20		
November 2010	2,984	34.06		
December 2010	15,753	35.60		
Fourth Quarter Total	22,346	34.69		

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2005 (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.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Forest Oil Corporation, the S&P 500 Index,
and The Dow Jones US Exploration & Production Index

*$100 invested on 12/31/05 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

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.

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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, 2010. 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,				
	2010	2009	2008	2007	2006
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Oil, natural gas, and NGL sales[1]	$ 853,739	$ 767,830	$ 1,647,171	$ 1,083,081	$ 814,469
Earnings (loss) from continuing operations	227,521	(923,133)	(1,026,323)	169,306	166,080
Earnings from discontinued operations, net of tax[2]					2,422
Net earnings (loss)	$ 227,521	$ (923,133)	$ (1,026,323)	$ 169,306	$ 168,502
Basic earnings (loss) per share:[3]					
Earnings (loss) from continuing operations	$ 2.01	$ (8.85)	$ (11.46)	$ 2.20	$ 2.64
Earnings from discontinued operations, net of tax					.04
Basic earnings (loss) per common share	$ 2.01	$ (8.85)	$ (11.46)	$ 2.20	$ 2.68
Diluted earnings (loss) per share:[3]					
Earnings (loss) from continuing operations	$ 2.00	$ (8.85)	$ (11.46)	$ 2.16	$ 2.60
Earnings from discontinued operations, net of tax					.04
Diluted earnings (loss) per common share	$ 2.00	$ (8.85)	$ (11.46)	$ 2.16	$ 2.64
Total assets	$ 3,785,388	$ 3,684,690	$ 5,282,798	$ 5,695,548	$ 3,189,072
Long-term debt	$ 1,869,372	$ 2,022,514	$ 2,735,661	$ 1,503,035	$ 1,204,709
Shareholders' equity	$ 1,352,787	$ 1,079,154	$ 1,672,912	$ 2,411,811	$ 1,434,006
OPERATING DATA					
Annual production:					
Natural gas (MMcf)	123,782	139,277	141,433	108,042	73,024
Oil (MBbls)	3,185	4,023	4,580	5,297	5,982
NGLs (MBbls)	3,723	3,242	3,451	2,648	2,044
Average sales price:[1]					
Natural gas (per Mcf)	$ 3.94	$ 3.30	$ 7.45	$ 5.79	$ 5.58
Oil (per Bbl)	$ 73.85	$ 55.98	$ 95.07	$ 66.44	$ 56.45
NGLs (per Bbl)	$ 35.16	$ 25.57	$ 45.94	$ 39.75	$ 33.85

(1) Includes the effects of hedging under cash flow hedge accounting in 2006.

(2) Discontinued operations relate to the sale of the business assets of our Canadian marketing subsidiary.

(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 have 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, 2010 were approximately 2,244 Bcfe of which 81% were in the United States, 17% were in Canada, and 2% were in Italy. Approximately 78% of our estimated proved reserves were natural gas as of December 31, 2010. We currently conduct our operations in three geographical segments: the United States, Canada, and International. See Note 14 to the Consolidated Financial Statements for additional information about our geographical segments. 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 ("IPO") of up to 19.9% of the common stock of our wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which will be the holding company of the Canadian operations, followed by a distribution of the remaining shares of Lone Pine held by us to our shareholders. The proceeds from the IPO will be used to repay intercompany debt owed to Forest, and the remainder, if any, for general corporate purposes. We expect the IPO to occur in the first half of 2011 and the spin-off of the remaining shares of Lone Pine is expected to occur approximately four months after the IPO; however, we will retain the right to decide whether to commence the spin-off at our discretion. See Part I, Item 1A "Risk Factors *We may be unable to complete the separation of our Canadian operations as planned or on the terms and manner currently contemplated, and any completed separation may have a negative impact on our business operations, results of operations and financial condition*."

2010 Summary

A summary of Forest's 2010 results is as follows:

- Oil, natural gas, and natural gas liquids ("NGL") sales volumes decreased 10% to 453 MMcfe per day in 2010 from 501 MMcfe per day in 2009 due to the sale of approximately $1 billion of non-core oil and gas properties primarily in late 2009. Average daily sales volumes, pro forma for oil and gas property divestitures, increased approximately 5% from 2009 to 2010. See Item 1 "Business Acquisition and Divestiture Activities" for a summary of our acquisitions and divestitures during the last several years.

- Oil, natural gas, and NGL sales increased 11% in 2010 to $854 million from $768 million in 2009. The increase was due to a 23% increase in realized prices partially offset by a 10% decrease in sales volumes.

- Lease operating expenses were 11% lower on a per-unit basis in 2010 as compared to 2009. The decrease was attributable to cost reduction initiatives and the sale of non-core oil and gas properties in late 2009 that had higher per-unit operating costs as compared to the properties we retained.

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Net earnings increased $1.2 billion to $228 million ($2.00 per diluted share) in 2010, compared to a net loss of $923 million ($8.85 per diluted share) in 2009, primarily due to a $1.6 billion pre-tax ceiling test write-down recorded in 2009. See "Results of Operations" below.

Net cash provided by operating activities decreased $64 million to $533 million in 2010 from $597 million in 2009 primarily due to lower realized gains on commodity derivative instruments of $197 million, partially offset by an increase in commodity prices and a reduction in our current income tax expense.

Recent Trends

Beginning in the second half of 2008 and continuing throughout 2009, the United States and other industrialized countries experienced a significant economic slowdown, which led to a decline in worldwide energy demand. During the same time period, North American natural gas supply increased as a result of increased domestic unconventional gas production. The combination of lower energy demand and higher North American gas supply resulted in significant declines in oil, natural gas, and NGL prices beginning in mid-2008. While oil and NGL prices have steadily improved since the first quarter of 2009 as the worldwide demand for the products increased, North American natural gas prices have not improved proportionate to the increases in oil and NGL prices due to increased domestic supply of natural gas and continued weak industrial demand for natural gas in the United States. For example, the NYMEX WTI price, which is a widely-used benchmark in the pricing of oil and NGLs, increased approximately 105% from $44.60 on December 31, 2008 to $91.38 on December 31, 2010 while the NYMEX Henry Hub price, a widely-used benchmark in the pricing of natural gas, decreased 27% to $4.19 from $5.71 between those same dates.

We expect the volatility in oil, natural gas, and NGL prices to continue in 2011 due primarily to the uncertainty surrounding the worldwide economic recovery and supply and demand fundamentals, particularly for North American natural gas. In this environment, we have hedged approximately 51 Bcfe of our 2011 natural gas production at a weighted-average NYMEX Henry Hub price of $5.54 per MMBtu and 1,460 MBoe of our 2011 oil production at a weighted-average NYMEX WTI floor and ceiling price of approximately $77.50 per barrel and $88.90 per barrel, respectively. Furthermore, as a result of the strength in oil and NGL prices relative to natural gas prices, we expect to direct approximately 80% of our exploration and development capital expenditures in 2011 to liquids-rich prospects. See Item 1 "Business Core Operational Areas" for a summary of our core operational areas of focus and the amount of capital expenditures we expect to invest in those areas in 2011.

Results of Operations

The following table sets forth selected operating results for the years ended December 31, 2010, 2009, and 2008.

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands, Except per Mcfe and per Share Data)		
Oil, natural gas, and NGL sales	$ 853,739	$ 767,830	$ 1,647,171
Realized equivalent sales price (per Mcfe)	5.17	4.20	8.69
Net earnings (loss)	227,521	(923,133)	(1,026,323)
Diluted earnings (loss) per common share	2.00	(8.85)	(11.46)
Adjusted EBITDA[1]	718,977	794,717	1,262,713

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

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Our net earnings (loss) and diluted earnings (loss) per share presented in the table above were primarily impacted by changes in total oil, natural gas, and NGL sales driven by price fluctuations of those commodities between the periods presented and, in 2009 and 2008, due to non-cash ceiling test write-downs of $1.6 billion and $2.4 billion, respectively. Adjusted EBITDA, which excludes the impact of ceiling test write-downs, decreased $76 million to $719 million in 2010 from $795 million in 2009 due to a $197 million decrease in realized commodity hedging gains partially offset by a $86 million increase in oil, natural gas, and NGL sales driven by higher commodity prices. Adjusted EBITDA decreased $468 million in 2009 compared to 2008 due to the significant decrease in oil and natural gas prices during that same period to $4.20 per Mcfe in 2009 from $8.69 per Mcfe in 2008.

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

Oil and Natural Gas Volumes and Revenues

Natural gas, oil, and NGL sales volumes, revenues, and average sales prices by location for the years ended December 31, 2010, 2009, and 2008, are set forth in the table below.

	Year Ended December 31,											
	2010				**2009**				**2008**			
	Natural Gas	**Oil**	**NGLs**	**Total**	**Natural Gas**	**Oil**	**NGLs**	**Total**	**Natural Gas**	**Oil**	**NGLs**	**Total**
Sales volumes:	(MMcf)	(MBbls)	(MBbls)	**(MMcfe)**	(MMcf)	(MBbls)	(MBbls)	**(MMcfe)**	(MMcf)	(MBbls)	(MBbls)	**(MMcfe)**
United States	101,346	2,357	3,589	**137,022**	116,029	3,397	3,012	**154,483**	118,120	3,778	3,151	**159,694**
Canada	22,436	828	134	**28,208**	23,248	626	230	**28,384**	23,313	802	300	**29,925**
Totals	123,782	3,185	3,723	**165,230**	139,277	4,023	3,242	**182,867**	141,433	4,580	3,451	**189,619**
Revenues (In Thousands):												
United States	$ 404,415	$ 179,312	$ 123,965	**$ 707,692**	$ 386,581	$ 193,185	$ 75,813	**$ 655,579**	$ 890,417	$ 365,913	$ 140,339	**$ 1,396,669**
Canada	83,226	55,896	6,925	**146,047**	73,147	32,016	7,088	**112,251**	162,769	69,520	18,213	**250,502**
Totals	$ 487,641	$ 235,208	$ 130,890	**$ 853,739**	$ 459,728	$ 225,201	$ 82,901	**$ 767,830**	$ 1,053,186	$ 435,433	$ 158,552	**$ 1,647,171**
Average sales price per unit:	$/Mcf	$/Bbl	$/Bbl	**$/Mcfe**	$/Mcf	$/Bbl	$/Bbl	**$/Mcfe**	$/Mcf	$/Bbl	$/Bbl	**$/Mcfe**
United States	$ 3.99	$ 76.08	$ 34.54	**$ 5.16**	$ 3.33	$ 56.87	$ 25.17	**$ 4.24**	$ 7.54	$ 96.85	$ 44.54	**$ 8.75**
Canada	3.71	67.51	51.68	**5.18**	3.15	51.14	30.82	**3.95**	6.98	86.68	60.71	**8.37**
Totals	$ 3.94	$ 73.85	$ 35.16	**$ 5.17**	$ 3.30	$ 55.98	$ 25.57	**$ 4.20**	$ 7.45	$ 95.07	$ 45.94	**$ 8.69**

Our average daily sales volumes in 2010 were 453 MMcfe/d compared to 501 MMcfe/d in 2009. The decrease of 48 MMcfe/d was due to non-core oil and gas property divestitures that occurred primarily in late 2009 offset by production increases attributable to new wells drilled in 2010. Average daily sales volumes, pro forma for oil and gas property divestitures, increased approximately 5% from 2009 to 2010. Oil and natural gas revenues in 2010 were $854 million, an 11% increase as compared to $768 million in 2009. The increase in oil and natural gas revenues was due primarily to the 23% increase in the average realized sales price, which increased to $5.17 per Mcfe in 2010 from $4.20 per Mcfe in 2009, partially offset by the decrease in sales volumes.

Our average daily sales volumes decreased 17 MMcfe/d to 501 MMcfe/d in 2009 from 518 MMcfe/d in 2008. The decrease was primarily due to a reduction in drilling and acquisition activity in 2009 compared to 2008. Oil and natural gas revenues in 2009 were $768 million, a 53% decrease as compared to $1.6 billion in 2008. The decrease in oil and natural gas revenues was due primarily to the 52% decrease in the average realized sales price, which decreased to $4.20 per Mcfe in 2009 from $8.69 per Mcfe in 2008.

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 for the periods indicated.

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands, Except per Mcfe Data)		
Production expense:			
Lease operating expenses	$ 118,074	$ 146,977	$ 167,830
Production and property taxes	46,079	42,903	82,147
Transportation and processing costs	23,980	20,915	19,472
Production expense	$ 188,133	$ 210,795	$ 269,449
Production expense per Mcfe:			
Lease operating expenses	$ .71	$ .80	$ .89
Production and property taxes	.28	.23	.43
Transportation and processing costs	.15	.11	.10
Production expense per Mcfe	$ 1.14	$ 1.15	$ 1.42

Lease Operating Expenses

Lease operating expenses decreased 20% to $118 million in 2010 from $147 million in 2009. On a per-unit basis, lease operating expenses decreased 11% to $.71 per Mcfe in 2010 from $.80 per Mcfe in 2009. The decrease in total and per-unit lease operating expenses was primarily due to non-core 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. Lease operating expenses decreased 12% to $147 million in 2009 from $168 million in 2008. On a per-unit basis, lease operating expenses decreased 10% to $.80 per Mcfe in 2009 from $.89 per Mcfe in 2008. The decrease in total and per-unit lease operating expenses was attributable to company-wide cost reduction initiatives.

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 5.4%, 5.6%, and 5.0% of oil, natural gas, and NGL revenues for the years ended December 31, 2010, 2009, and 2008, 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 $24 million, or $.15 per Mcfe, in 2010, $21 million, or $.11 per Mcfe, in 2009, and $19 million, or $.10 per Mcfe, in 2008. Transportation and processing costs increased in 2010 primarily due to higher transportation costs incurred for our Canadian and North Louisiana production where additional downstream capacity was purchased.

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General and Administrative Expense

The following table summarizes the components of general and administrative expense incurred during the periods indicated.

	Year Ended December 31, 2010	2009	2008
	(In Thousands, Except Per Mcfe Data)		
Stock-based compensation costs	$ 35,010	$ 29,165	$ 27,012
Other general and administrative costs	86,400	88,935	95,002
General and administrative costs capitalized	(48,206)	(47,024)	(47,282)
General and administrative expense	$ 73,204	$ 71,076	$ 74,732
General and administrative expense per Mcfe	$ .44	$ .39	$ .39

General and administrative expense increased $2 million to $73 million in 2010 from $71 million in 2009. The increase in general and administrative expense is primarily due to higher stock-based incentive compensation costs primarily driven by an increase in our stock price in 2010. General and administrative expense decreased approximately $4 million to $71 million in 2009 from $75 million in 2008 primarily due to lower software and contract employee expense. The percentage of general and administrative costs capitalized under the full cost method of accounting remained relatively constant between the three years, ranging between 39% and 40%.

Depreciation, Depletion, and Amortization

The following table summarizes depreciation, depletion, and amortization expense incurred during the periods indicated.

	Year Ended December 31, 2010	2009	2008
	(In Thousands, Except Per Mcfe Data)		
Depreciation, depletion, and amortization expense	$ 251,618	$ 303,622	$ 532,181
Depreciation, depletion, and amortization expense per Mcfe	$ 1.52	$ 1.66	$ 2.81

Depreciation, depletion, and amortization expense ("DD&A") decreased $.14 per Mcfe to $1.52 in 2010 compared to $1.66 in 2009 primarily due to a $1.6 billion non-cash ceiling test write-down of our depletable base recorded in the first quarter 2009. DD&A decreased $1.15 per Mcfe to $1.66 in 2009 compared to $2.81 in 2008 primarily due to a $2.4 billion non-cash ceiling test write-down recorded in the fourth quarter 2008 and a $1.6 billion non-cash ceiling test write-down recorded in the first quarter 2009.

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 both its United States and Canadian cost centers totaling $1.6 billion in the first quarter 2009. In the fourth quarter of 2008, Forest recorded a $2.4 billion non-cash ceiling test write-down for its United States cost center. The write-downs were a result of significant declines in oil and natural gas prices in the fourth quarter of 2008 and the first quarter of 2009. See "Critical Accounting Policies, Estimates, Judgments and Assumptions *Full Cost Method of Accounting*" and Part II, Item 1A, "Risk Factors *Lower oil and gas prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values*."

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Interest Expense

The following table summarizes interest expense incurred during the periods indicated.

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands)		
Interest costs	$ 161,531	$ 175,662	$ 143,534
Interest costs capitalized	(12,008)	(12,175)	(17,855)
Interest expense	$ 149,523	$ 163,487	$ 125,679

Interest expense in 2010 totaled $150 million compared to $163 million in 2009. The $14 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 our $150 million $7^3/_4$% senior notes. In addition, in December 2009, we repaid all amounts outstanding under our credit facilities using proceeds from non-core oil and gas property sales and have used the credit facilities only to fund short-term borrowing needs during 2010. Interest expense in 2009 totaled $163 million compared to $126 million in 2008. The $38 million increase in interest expense was primarily attributable to the use of debt to fund the $570 million cash portion of the acquisition of oil and gas assets from Cordillera Texas, L.P. in September 2008. 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, Forest began entering into fixed-to-floating interest rate swaps in the first quarter of 2009 under which it has swapped, as of December 31, 2010, $500 million in notional amount at an 8.5% fixed rate for an equal notional amount at a weighted-average rate equal to the 1-month LIBOR plus approximately 5.9%. Forest recognized realized gains under these interest rate swaps of $11 million and $7 million during the years ended December 31, 2010 and 2009, respectively. These gains are recorded as realized gains on derivatives rather than as a reduction to interest expense since Forest has not elected to use hedge accounting. See Note 10 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 recognized under "Costs, expenses, and other" in our Consolidated Statements of Operations for the periods indicated.

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See Note 9 and Note 10 to the Consolidated Financial Statements for more information on our derivative instruments.

	Year Ended December, 31		
	2010	2009	2008
	(In Thousands)		
Realized losses (gains) on derivatives, net:			
Oil	$ 3,825	$ (11,632)	$ 71,198
Natural Gas	(103,587)	(285,576)	(16,126)
Interest	(12,450)	(10,958)	889
Subtotal realized	(112,212)	(308,166)	55,961
Unrealized losses (gains) on derivatives, net:			
Oil	18,978	35,771	(118,151)
Natural Gas	(47,078)	139,728	(98,618)
NGLs	9,710		
Interest	(19,530)	519	(4,721)
Subtotal unrealized	(37,920)	176,018	(221,490)
Realized and unrealized gains on derivatives, net	$ (150,132)	$ (132,148)	$ (165,529)

Gain on Sale of Assets

In 2008, Forest sold all of its unproved oil and gas properties in Gabon for $24 million, which resulted in a gain of $21 million.

Other, Net

The table below sets forth the components of "Other, net" in our Consolidated Statements of Operations for the periods indicated.

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands)		
Unrealized foreign currency exchange (gains) losses, net	$ (14,290)	$ (17,974)	$ 19,481
Realized foreign currency exchange (gains) losses, net	(270)	(88)	959
Unrealized losses on other investments, net		2,327	34,042
Accretion of asset retirement obligations	7,194	8,311	7,602
(Gain) loss on debt extinguishment, net	(4,576)		97
Other, net	6,199	16,812	5,076
	$ (5,743)	$ 9,388	$ 67,257

Foreign Currency Exchange

Realized and unrealized foreign currency exchange gains and losses relate to outstanding intercompany indebtedness and advances, which are denominated in U.S. dollars, between Forest Oil Corporation and its wholly-owned Canadian subsidiary whose functional currency in the Canadian dollar.

Unrealized Losses on Other Investments

Unrealized losses on other investments relate to fair value adjustments to the shares of Pacific Energy Resources, Ltd. ("PERL") common stock and the zero coupon senior subordinated note from

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PERL due 2014, which were received as a portion of the total consideration for the sale of our Alaska assets in August 2007. In March 2009, PERL filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code and subsequently indicated that the value of its assets is less than the amount of its senior unsubordinated debt. See Note 9 to the Consolidated Financial Statements for more information on these investments, each of which has had a zero fair value since March 31, 2009.

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.

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 all $150 million of our 7$^3/_4$% 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 senior notes. This gain was partially offset by the $1.9 million redemption premium paid to redeem the notes. See Note 4 to the Consolidated Financial Statements for more information on our debt.

Income Tax

The table below sets forth Forest's total income tax from continuing operations and effective tax rates for the periods indicated.

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands, Except Percentages)		
Current income tax	$ (13,901)	$ 70,815	$ 11,139
Deferred income tax	134,528	(581,290)	(585,817)
Total income tax	$ 120,627	$ (510,475)	$ (574,678)
Effective tax rate	35%	36%	36%

Our combined U.S. and Canadian effective tax rate generally approximates 35% to 36% but will fluctuate based on the percentage of pre-tax income generated in the U.S. versus Canada. The current provision for income taxes increased to $71 million in 2009 due primarily to $933 million in asset sales in the United States which contributed to taxable income in excess of our available net operating loss carryforwards in 2009. See Note 5 to the Consolidated Financial Statements for a reconciliation of our income taxes at the statutory rate to income taxes at our effective rate for each period presented.

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 facilities 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.

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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 75% of our total production in 2010 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 17, 2011, we had hedged, via commodity swaps and collar instruments, approximately 71 Bcfe of our total 2011 production, excluding outstanding commodity call 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 2011. 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 result in financial losses or reduce our income*," 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 17, 2011, all of our derivative instrument counterparties are commercial banks that are parties to our credit facilities, or their affiliates. 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 call options.

The other primary source of liquidity is our combined U.S. and Canadian credit facilities, which had an aggregate borrowing base of $1.3 billion as of December 31, 2010. These facilities are used to fund daily operations and to fund acquisitions and refinance debt, as needed and if available. The credit facilities are secured by a portion of our assets and mature in June 2012. See "*Bank Credit Facilities*" below for further details. We had no amounts drawn on our credit facilities as of December 31, 2010 and February 18, 2011.

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 $600 million principal amount of 8$^1/_2$% 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 2010, we sold certain non-strategic assets for approximately $166 million and, during 2009, we sold certain non-strategic assets for approximately $1.1 billion, a portion of which proceeds were used to pay off the outstanding balances under our credit facilities in 2009 and redeem our 7$^3/_4$% senior notes due 2014 in January 2010.

We believe that our current cash and cash equivalents, cash flows provided by operating activities, and $1.3 bil