FOREST OIL CORP
Form 10-K
March 01, 2010

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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, 2009

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 the 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, 2009, the last business day of the registrant's most recently completed second fiscal quarter, was $1,660,195,622 (based on the closing price of such stock).

There were 112,428,756 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 19, 2010.

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, 2009 are incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1. Business.

General

Forest Oil Corporation ("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 reserves as of December 31, 2009 were approximately 2,121 Bcfe. At December 31, 2009, approximately 83% of Forest's estimated proved oil and gas reserves were in the United States, approximately 15% were in Canada, and approximately 2% were in Italy.

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 and Section 21E of the Securities Exchange Act of 1934. 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," below, for the definition of certain terms.

Strategy

Over the last six years, we have pursued a strategy directed at transforming Forest from a predominantly offshore Gulf of Mexico oil and gas producer to a North American onshore company with a focus on unconventional resource plays having numerous lower risk opportunities for production and reserve growth. An integral part of this strategy has been the acquisition of properties in several core operational areas of focus while divesting our non-core assets outside of those areas. We also seek to maintain financial flexibility as part of our business strategy, which includes maintaining capital discipline and focusing on cost control.

Core Operational Areas

Forest's core operational areas, where the majority of its exploration and development activities are planned in 2010, are detailed below. Our 2010 budget provides for a significant increase in the level of drilling activity in these core areas compared to 2009. In addition to the core operational areas below, Forest owns and operates producing oil and gas properties throughout North America.

The Greater Buffalo Wallow Area

The Greater Buffalo Wallow area extends over a large area in the Texas Panhandle and Western Oklahoma. Forest holds approximately 94,000 net acres in the area primarily located in Hemphill, Lipscomb, Roberts, and Wheeler Counties in the Texas Panhandle. The area provides for excellent horizontal and vertical drilling opportunities targeting liquids-rich Granite Wash intervals as well as other multi-pay objectives such as the Atoka and Morrow formations. We drilled our first horizontal wells in the area in 2009, leveraging our database of over 400 wells in the area to determine attractive formations throughout our acreage position to initiate a horizontal drilling campaign. Based on the results of the first four operated horizontal wells drilled in the area, which had initial 24-hour production rates of approximately 30 MMcfe per day, we plan to significantly increase the number of horizontal wells drilled in 2010 by employing up to a four rig program, investing approximately $150 million for, among other projects, the drilling of 20 to 25 gross horizontal wells.

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East Texas / North Louisiana Area

The East Texas / North Louisiana area includes our interests in approximately 154,000 net acres that are prospective for the Cotton Valley, Haynesville, Bossier and other formations. Since our entry into East Texas in 2006, we primarily targeted tight-gas sands in the Cotton Valley formation. In 2009, we expanded our drilling program in the region and drilled seven wells targeting the Haynesville formations, including four horizontal wells in Louisiana. These four wells had average initial 24-hour production rates of 18 MMcfe per day. In 2010, we plan to operate up to four rigs in the area and invest approximately $160 million for, among other projects, the drilling of 12 to 16 gross horizontal wells targeting the Haynesville Shale in North Louisiana and six to eight gross horizontal wells targeting the Cotton Valley Sands or Haynesville/Bossier formations in East Texas and North Louisiana

Canadian Deep Basin Area

The Canadian Deep Basin area is located in Alberta and British Columbia and primarily includes our interests in the Wild River, Narraway, Ojay, and Evi fields. As we did with our Greater Buffalo Wallow area development strategy, we plan to further delineate the Narraway, Ojay, and Wild River fields through the drilling of vertical wells to evaluate multiple objectives in these fields to potentially employ a horizontal drilling program in the future. Forest holds approximately 88,000 net acres in the basin and we plan to run up to a seven rig program during 2010. We intend to invest approximately $170 million in 2010 for, among other projects, the drilling of between 35 to 40 operated wells including horizontal wells in our oil-rich Evi field as well as vertical wells where multi-pay zones are being targeted in our Narraway, Ojay, and Wild River fields. The capital budget for the Deep Basin in 2010 was increased compared to prior years to take advantage of the current favorable royalty regime in place in Alberta.

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 Greater Buffalo Wallow 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 based on a September 30, 2008 closing date. As of the closing date of the acquisition, the assets included approximately 350 Bcfe of estimated proved reserves and 85,000 net acres.

In May 2008, we acquired producing oil and natural gas properties located primarily in our East Texas / North Louisiana core area for approximately $284 million. As of the closing date of the acquisition, the assets included approximately 110 Bcfe of estimated proved reserves and 47,000 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, exploitation, and acquisition of natural gas and oil reserves in North

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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 $30.28 per share.

In March 2006, we acquired oil and natural gas properties located in our East Texas / North Louisiana core area for approximately $255 million in cash. As of the closing date of the acquisition, the assets included approximately 110 Bcfe of estimated proved reserves and approximately 26,000 net acres.

In April 2005, we acquired oil and natural gas properties in the Greater Buffalo Wallow core area for approximately $197 million in cash and the assumption of $35 million in debt. As of the closing date of the acquisition, the assets included approximately 120 Bcfe of estimated proved reserves and approximately 28,000 net acres.

Divestitures

During 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 November 2008, we sold the majority of our oil and gas properties located in the Rocky Mountains for approximately $198 million in cash. We estimated the proved reserves associated with these properties were 75 Bcfe at closing.

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 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, 2009, based on the Henry Hub price of $3.87 per MMBtu for natural gas and the West Texas Intermediate price of $61.08 per barrel for oil, each of which represents the unweighted arithmetic average of the first-day-of-the-month prices during the twelve-month period prior to December 31,

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2009. See "*Preparation of Reserves Estimates*" below and Note 17 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)**
Developed:			
United States	916,005	34,364	1,122,189
Canada	169,740	6,202	206,952
Total developed	1,085,745	40,566	1,329,141
Undeveloped:			
United States	499,426	20,804	624,250
Canada	51,461	10,652	115,373
Italy	51,738		51,738
Total undeveloped	602,625	31,456	791,361
Total estimated proved reserves	1,688,370	72,022	2,120,502

As of December 31, 2009, Forest had estimated proved reserves of 2,121 Bcfe. Of that total, 1,746 Bcfe (83%) were in the United States, 322 Bcfe (15%) were in Canada, and 52 Bcfe (2%) were in Italy. During 2009, we added 663 Bcfe of estimated proved reserves through extensions and discoveries which were offset by property sales of 628 Bcfe, negative performance revisions of 88 Bcfe, and negative product price revisions of 312 Bcfe, which were primarily related to a decrease in the natural gas price required to be assumed to calculate reserves volumes.

As of December 31, 2009, proved undeveloped reserves ("PUDs") were estimated to be 791 Bcfe, or 37% of estimated proved reserves, compared to 989 Bcfe, or 37% of estimated proved reserves as of December 31, 2008. The net reduction of 198 Bcfe was primarily due to negative price-related revisions and asset sales offset by extensions and discoveries. See "Strategy *Acquisition and Divestiture Activities Divestitures*" above for a discussion of the divestitures completed during 2009. We invested $74 million to convert 32 Bcfe of our December 31, 2008 PUD reserves to proved developed reserves during 2009. During the years 2006 to 2008, we converted, on average, 120 Bcfe per year from PUD reserves to proved developed reserves. We intend to convert the PUDs recorded as of December 31, 2009 to proved developed reserves within five years.

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" rules, which were 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 December 31, 2009, with 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. Prior to the new rules, estimated proved reserves were calculated using year-end spot prices, including the consideration of changes in existing prices provided only by contractual arrangements and excluding escalations based upon future conditions. In the table below, Forest presents estimated quantities of proved reserves as of December 31, 2009 using

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the year-end Henry Hub spot price of $5.79 per MMBtu for natural gas and the year-end West Texas Intermediate spot price of $79.36 per barrel for oil.

	Estimated Proved Reserves Alternative Pricing(1)		
	Natural Gas (Bcf)	Oil and Natural Gas Liquids (MMBbls)	Total (Bcfe)
Total estimated proved reserves	2,018	81	2,503

(1) Pricing based on the December 31, 2009 spot prices for natural gas and oil.

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 the unweighted arithmetic average first-day-of-the-month prices during the twelve-month period prior to December 31, 2009 as well as the alternative pricing of $5.79 per MMBtu for natural gas and $79.36 per barrel for oil. Forest presents the pre-tax PV-10 value, which is not a financial measure accepted under Generally Accepted Accounting Principals ("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	Alternative Price
Henry Hub natural gas price	$ 3.87	5.79
West Texas Intermediate oil price	61.08	79.36
Pre-tax PV-10 value (in thousands)	$ 2,337,342	4,495,542
Less: Income tax effects discounted at 10% per annum (in thousands)	284,343	1,124,490
Standardized measure of discounted future net cash flows (in thousands)	$ 2,052,999	3,371,052

Preparation of Reserves Estimates

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

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and 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," for a description of some of the risks and uncertainties associated with our business and reserves.

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 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 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 the Company in early 2001. Prior to joining the Company, 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 is a twenty-five year member of the Society of Petroleum Engineers.

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 five percent of the independent reserve engineers' quantity estimates on a Company basis and within ten percent 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, 2009, 2008, and 2007, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the

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year ended December 31, 2009, DeGolyer and MacNaughton independently audited estimates relating to properties constituting approximately 85% of our reserves by NPV as of December 31, 2009. When compared on a field-by-field basis, some of Forest's estimates of proved reserves were greater and some were lesser than the estimates prepared by DeGolyer and MacNaughton. However, in the aggregate, Forest's estimates of total proved reserves were within five percent 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

During 2009, we drilled a total of 117 gross wells, of which 28 were classified as exploratory and 89 were classified as development. Our 2009 drilling program achieved a 94% success rate. The following table summarizes the number of wells drilled during 2009, 2008, and 2007, 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, 2009, we had 21 gross (11 net) wells in progress in the United States and 10 gross (6 net) wells in progress in Canada.

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
United States						
Productive	76	47	550	323	374	207
Non-productive(1)	6	4	15	11	16	13
Total	82	51	565	334	390	220
Canada						
Productive	7	3	64	39	52	32
Non-productive(1)					1	1
Total	7	3	64	39	53	33
Total development wells	89	54	629	373	443	253
Exploratory wells, completed as:						
United States						
Productive	23	14	72	54	38	25
Non-productive(1)			3	2	5	3
Total	23	14	75	56	43	28
Canada						
Productive	4	2	10	8	7	3
Non-productive(1)						
Total	4	2	10	8	7	3
Italy						
Productive					2	2
Non-productive(1)	1	1				
Total	1	1			2	2
Total exploratory wells	28	17	85	64	52	33

(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).

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Oil and Gas Wells and Acreage

Productive Wells

Productive wells consist of producing wells and wells capable of production, including shut-in wells. A well bore with multiple completions is counted as only one well. As of December 31, 2009, Forest owned interests in 545 gross wells containing multiple completions. The following table summarizes our productive wells as of December 31, 2009, all of which are located in the United States, Canada, and Italy.

	United States		Canada		Italy		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gas	3,735	2,801	565	357	2	2	4,302	3,160
Oil	371	234	364	258			735	492
Total	4,106	3,035	929	615	2	2	5,037	3,652

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, 2009. 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, 2009, approximately 8%, 13%, and 10% of our net undeveloped acreage in the United States and Canada was held under leases that will expire in 2010, 2011, and 2012, respectively, if not extended by exploration or production activities.

	Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net
United States:				
Western[(1)]	258,123	119,580	211,305	121,513
Eastern[(2)]	237,903	171,520	142,729	78,578
Southern[(3)]	207,309	135,092	109,848	100,805
	703,335	426,192	463,882	300,896
Canada[(4)]	251,120	148,246	812,021	606,951
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	956,955	576,688	4,336,141	2,613,846

(1) The Western Business Unit's acreage is primarily located in the Greater Buffalo Wallow area in the Texas Panhandle and Western Oklahoma as well as in the Uintah field in Utah.

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

(3) The Southern Business Unit's acreage is primarily located in South Texas.

(4) The Canadian Business Unit's acreage is primarily located in the Deep Basin area in Alberta and British Columbia as well as in the St. Lawrence Lowlands in Quebec.

(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 is expected to be executed in 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, 2009, 2008, and 2007 by geographical area. Forest does not have any fields that contain 15% or more of the Company's total estimated proved reserves.

	United States			Canada			Total Company		
	2009	2008	2007	2009	2008	2007	2009	2008	2007
Natural Gas:									
Average sales price (per Mcf)	$ 3.33	7.54	5.95	3.15	6.98	5.29	3.30	7.45	5.79
Production volumes (MMcf)	116,029	118,120	82,963	23,248	23,313	25,079	139,277	141,433	108,042
Liquids:									
Oil and condensate:									
Average sales price (per Bbl)	$ 56.87	96.85	67.91	51.14	86.68	58.05	55.98	95.07	66.44
Production volumes (MBbls)	3,397	3,778	4,504	626	802	793	4,023	4,580	5,297
Natural gas liquids:									
Average sales price (per Bbl)	$ 25.17	44.54	39.32	30.82	60.71	43.54	25.57	45.94	39.75
Production volumes (MBbls)	3,012	3,151	2,381	230	300	267	3,242	3,451	2,648
Total liquids:									
Average sales price (per Bbl)	$ 41.97	73.06	58.02	45.68	79.61	54.40	42.41	73.96	57.54
Production volumes (MBbls)	6,409	6,929	6,885	856	1,102	1,060	7,265	8,031	7,945
Average sales price (per Mcfe)	$ **4.24**	**8.75**	**7.18**	**3.95**	**8.37**	**6.05**	**4.20**	**8.69**	**6.96**
Total production volumes (MMcfe)	**154,483**	**159,694**	**124,273**	**28,384**	**29,925**	**31,439**	**182,867**	**189,619**	**155,712**
Production costs (per Mcfe):									
Lease operating expenses	$ .77	.83	1.09	.97	1.21	1.00	.80	.89	1.08
Transportation and processing costs	.08	.06	.08	.28	.32	.33	.11	.10	.13
Production costs excluding production and property taxes (per Mcfe)	.86	.89	1.17	1.25	1.53	1.33	.92	.99	1.21
Production and property taxes	.26	.49	.42	.10	.12	.11	.23	.43	.35
Total production costs (per Mcfe)	**$ 1.12**	**1.38**	**1.59**	**1.35**	**1.65**	**1.44**	**1.15**	**1.42**	**1.56**

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. We had no material delivery commitments as of February 25, 2010.

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.

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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. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have 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 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 or the Minerals Management Service, as applicable, 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 amends the Natural Gas Act ("NGA") to make it unlawful for "any entity,"

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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 $1,000,000 per day per violation. The new 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 anticipate we will be affected 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. The monitoring and reporting required by the new rules will likely increase our administrative costs. Forest does not anticipate it will be affected any differently than other producers of natural gas.

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 Forest in a manner significantly different from other oil and natural gas companies of similar size with operations 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 Forest and the landowners.

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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 framework establishes 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 new framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil range from 0% to 50%. Natural gas royalty rates range from 5% to 50%. In comparison, under the prior royalty regime, royalty rates ranged from 10% to 35% for conventional oil and from 5% to 35% for natural gas.

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), which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. 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 must shift to the new royalty framework 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, including the Deep Oil Exploration Program ("DOEP") and the Natural Gas Deep Drilling Program ("NGDDP"). These programs provide upfront royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 meters (6,562 feet) with a Crown interest and must be spudded after January 1, 2009. Oil wells in this category qualify for a royalty exemption on either the first $1,000,000 of royalty or the first 12 months of production. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 meters (8,202 feet). The NGDDP will have an escalating royalty credit in line with progressively deeper wells from $625 per meter ($191 per foot) to a maximum of $3,750 per meter ($1,143 per foot) and there are additional benefits for the deepest wells. A minimum 5% royalty will apply to these gas wells. Both the DOEP and the NGDDP are five year programs. Any wells drilled after December 31, 2013, will not qualify under either program. No royalty adjustments will be granted under either the DOEP or the NGDDP after December 31, 2018. 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 includes a drilling royalty credit for new oil, natural gas and non-project oil sands wells spudded and having a finished drill date between April 1, 2009 and March 31, 2011. This program provides a royalty credit of up to $200 per meter drilled with certain annual limitations on the amount of annual credits received directly from the Government. In addition, the program provides for a maximum 5% royalty rate for the first twelve months of production from wells that begin producing between April 1, 2009, and March 31, 2010, to a maximum of 50 MBbls of oil or 500 MMcf of natural gas.

Environmental

As an operator of oil and natural gas properties in the United States and Canada, and with exploratory and development operations in Italy and South Africa, we are subject to stringent national, state, provincial, and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil

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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 capital or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

We currently operate or lease, and have in the past operated or leased, a number of properties that for many years have been used for the exploration and production of oil and 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 closure 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 nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"). 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. Legislation to implement the Regulatory Framework had been expected to be put in place this year, but the federal government has delayed the release of any such regulation and potential federal requirements in respect of GHG emissions are unclear. On January 30, 2010, the Canadian federal government announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020, in order to align itself with U.S. policy. In 2009, the Canadian federal government announced its commitment to work with the provincial governments to implement a North America-wide cap and trade system for GHG emissions, in cooperation with the United States. Under the system, Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. 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 can take place at the provincial and municipal level. 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, effective July 1, 2007, requires mandatory emissions reductions through the use of emissions intensity targets, and 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 per ton of GHG emissions to the Alberta Climate Change and Management Fund. The Alberta government recently announced its intention to raise the price of fund credits. The Specified Gas Reporting Regulation imposes GHG emissions reporting requirements if a company has GHG emissions of 100,000 tons or more from a facility in a year. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations in permits and under other environmental regulations. 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.

In 2009, the U.S. House of Representatives passed a bill to control and reduce the emission of GHGs in the United States through the grant of emission allowances which would gradually be decreased over time, and the Senate is considering similar legislation. Moreover, nearly half of the states, 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, which could result in future regulation of GHG emissions from stationary and non-stationary sources, even if Congress does not adopt new legislation specifically addressing emissions of GHGs. In December 2009, the United States Environmental Protection Agency ("EPA") published its findings 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. Accordingly, the EPA has proposed regulations that would require a reduction of GHG emissions from motor vehicles and could trigger permit review for GHG emissions from large stationary sources such as power plants or industrial facilities. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources beginning in 2011 for emissions occurring in 2010. While it is not possible at this time to fully predict how legislation or new regulations that may be adopted in the United States to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have an adverse effect on demand for the oil and natural gas that we produce.

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.

Employees

As of December 31, 2009, we had 705 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 15 to the Consolidated Financial Statements of this Annual Report on Form 10-K.

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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 insure that production from our properties, if obtained, will be salable for the account of Forest.

Glossary of Oil and Gas Terms

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

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

Bcf. Billion cubic feet of natural gas.

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

Bbtu. One billion British Thermal Units.

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

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

Developed acreage. 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.

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.

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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.

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.

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. 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 ad valorem taxes, future capital costs, and operating expenses, but before deducting any estimates of U.S. federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC's practice, 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 and held constant for the life of the reserves.

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

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

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

Available Information

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

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

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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 of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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.

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

Item 1A. Risk Factors.

We are subject to certain risks and hazards due to the nature of the business activities we conduct, including the risks discussed below. The risks discussed below, any of which could materially and adversely affect our business, financial condition, cash flows, and results of operations, are not the only risks we face. We may experience additional risks and uncertainties not currently known to us; or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations.

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

Our financial condition, operating results, and future rate of growth depend upon the prices that we receive for our oil 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 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 spot prices reached historical highs in July 2008, and natural gas spot prices reached near historical highs in July 2008. Prices have declined significantly since that time and 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;

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- 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 fuels;
- domestic and foreign governmental regulations and taxes; and
- technological advances affecting energy consumption and supply.

These factors make it very difficult to predict future commodity price movements with any certainty. We sell the majority of our oil 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 80% of our estimated proved reserves at December 31, 2009 were natural gas, and, as a result, our financial results will be more sensitive to fluctuations in natural gas prices.

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

We require substantial capital expenditures to conduct our exploration, development, and production operations, engage in acquisition activities, and replace our production. 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.

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

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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.

The credit crisis and related turmoil in the global financial systems have had an impact on our business and our financial condition, and we may face additional challenges if economic and financial market conditions worsen.

The distressed economic conditions also may adversely affect the collectibility of our trade receivables. For example, our accounts receivable are primarily from purchasers of our oil and natural gas production and other exploration and production companies that own working interests in the properties that we operate This industry concentration could adversely impact our overall credit risk, because our customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices, and other conditions. Further, the credit crisis and turmoil in the financial markets could cause our commodity derivative instruments to be ineffective in the event a counterparty were unable to perform its obligations or seek bankruptcy protection.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, 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;
- 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

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- 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 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 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 but two 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

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

Among the changes contained in the Obama Administration's budget proposal for fiscal year 2011, released by the White House on February 1, 2010, is the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

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-

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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. 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 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 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, 2009, approximately 37% 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.

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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 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 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 surface 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 the 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 and may be less leveraged than we are. As a result, these companies may have greater access to capital and may be able to pay more for development prospects and producing properties, or evaluate and bid for a greater number of properties and prospects than our financial and staffing resources permit. Also, from time to time, we have to compete with financial investors in the property acquisition market, including private equity sponsors with more funds and access to additional liquidity. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and evaluate properties, available funds, and internal standards for minimum projected return on investment. In addition, while costs for equipment, 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 depends 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.

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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, our Canadian operations may be adversely affected by recent regulatory developments. The majority of our Canadian operations are located in Alberta, Canada, and in October 2007, the Alberta Government announced a new oil and gas royalty framework. The new framework went into effect on January 1, 2009. See Part I, "Business Regulation *Canada*" 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 not being able 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 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 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

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adversely affect our business and operations. See Part I, Item 1, "Business Regulation" for detail on both current and potential governmental regulation.

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.

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.

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 previously made the assertion that, in its role as assignor of the Alaska

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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. Forest disagrees with the working interest owners' assertion and, to the extent necessary, will vigorously oppose any efforts to hold Forest liable for PERL's unsatisfied obligations. We cannot predict, however, whether we would be successful in avoiding liabilities associated with PERL's unsatisfied obligations.

Item 1B. Unresolved Staff Comments.

As of December 31, 2009, 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.

We are a party to various 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 in the reporting periods in which any such actions are resolved.

Item 4. Submission of Matters to a Vote of Security Holders.

No matter was submitted to a vote of our shareholders during the fourth quarter of the fiscal year ended December 31, 2009.

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Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of February 25, 2010.

Name	Age	Years with Forest	Office[1]
H. Craig Clark	53	9	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	35	9	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	54	6	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 most recently 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	59	21	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	53	7	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	46	8	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 of the law firm of Susman Godfrey L.L.P. in Houston, Texas.
Glen J. Mizenko	47	9	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	36	5	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	49	13	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	52	3	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 19, 2010, our Common Stock was held by 588 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. There were no cash dividends declared on the Common Stock in 2008 or 2009. On February 25, 2010, the closing price of Forest Common Stock was $26.83.

		Common Stock	
		High	Low
2008	First Quarter	$ 52.22	40.85
	Second Quarter	76.20	47.26
	Third Quarter	83.10	45.31
	Fourth Quarter	49.10	12.00
2009	First Quarter	$ 21.79	