FOREST OIL CORP
Form 10-K
February 26, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
(Mark One)

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

For the fiscal year ended December 31, 2013
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 o No x
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨	Accelerated filer x	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 x

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, was $483,491,861 (based on the closing price of such stock).

There were 119,076,708 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 19, 2014.

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, 2013 are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

Item 1. Business.

General

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

Forest is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids (sometimes referred to as “NGLs”) primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Forest’s total estimated proved oil and gas reserves as of December 31, 2013 were approximately 625 Bcfe, all of which are located in the United States.

Strategy

Forest’s long-term operating strategy seeks to build shareholder value by pursuing the development of oil and natural gas assets within our operational areas located in Eagle Ford in South Texas; Ark-La-Tex in East Texas, Louisiana, and Arkansas; and Permian Basin in West Texas. We strive to maintain a large number of commodity-diverse drilling locations that provide us with the flexibility to allocate capital to projects that generate the highest margins depending on the current commodity price environment, which currently include oil or natural gas liquids drilling projects. We devoted the majority of our capital expenditures to oil and natural gas liquids projects in 2013 and we plan to continue to do so in 2014. Our asset base and development efforts are focused in areas where we have concentrated land positions, a large drilling inventory, and operational control. Our growth strategy may also be supplemented from time to time through opportunistic acquisitions that complement our existing asset base to increase the size and scale of our development and resource opportunities. We may also sell properties when the opportunity arises or business conditions warrant, as demonstrated by the sale of our natural gas assets in South Texas and our Texas Panhandle properties in 2013.

Core Operational Areas

Our core operational areas consist of drilling projects that have exposure to oil, natural gas, and natural gas liquids. Our primary areas of focus in 2014 will be in Eagle Ford in South Texas and Ark-La-Tex in East Texas.

Eagle Ford

Our Eagle Ford assets are located in Gonzales County in South Texas. During 2013, we continued progress toward holding an aggregate of 49,000 gross (24,500 net) acres in the area and we currently anticipate that this will be accomplished during the first half of 2014. In April 2013, we announced a joint development agreement with an industry partner that allowed us to increase our pace of drilling activity during 2013 and implement technological refinements and enhancements. These enhancements involve ongoing micro-seismic and subsurface data analysis and reservoir studies that are being used to optimize well placement, lateral length, and fracture stimulation techniques and design. We are attempting to operate more efficiently through a combination of decreased drilling and completion time, the utilization of a more targeted completion design, and capitalizing on operational synergies associated with pad drilling. Drilling and completion costs for 2013 averaged $6 million per gross well as compared to $7 million for the wells drilled in 2012. In addition, we have entered into a gathering, treating, and processing agreement that will provide central facility gathering, transportation, gas processing, and water handling for our Eagle Ford production. This will help streamline our operations and provide cost savings for this oil asset. The facility is expected to be fully operational by the fourth quarter of 2014. We expect to see improvement in well costs following the completion of centralized production facilities, the use of existing pad locations, and continued optimization of completion techniques. In 2014, we plan to operate a two-rig drilling program in Eagle Ford.

Ark-La-Tex

We currently hold an acreage position of 234,000 gross (162,000 net) acres in the greater Ark-La-Tex. Approximately 78% of the acreage is held by production, of which 85% is operated by Forest. We believe that this asset base provides repeatable and predictable drilling and recompletion opportunities within multiple stacked-pay intervals, including the Cotton Valley, Haynesville, and other formations. Recent drilling activity has focused on the liquids-rich Cotton Valley and other formations in East Texas. During 2012, we changed our focus to target primarily liquids-rich drilling projects to take advantage of these higher-margin opportunities as a result of a decrease in natural gas prices. In 2013, we continued to primarily target the Cotton Valley formation and experienced relatively consistent and predictable results. We drilled a total of six wells in 2013 that had a 30-day average gross production rate of 8.7 MMcfe/d (40% liquids). In 2014, we plan to continue targeting the Cotton Valley and our efforts will focus on transitioning to multi-well pad drilling in certain areas to improve efficiency as we seek to reduce well costs. We plan to operate a three-rig drilling program in Ark-La-Tex during 2014.

Acquisition and Divestiture Activities

We currently have no plans for acquisitions. However, in the future we may pursue acquisitions that meet our criteria for investment returns. We also may divest non-core assets from time to time to, among other things, upgrade our portfolio, increase our operational efficiencies, and improve our financial position. As described below, we have focused on divestitures in recent years in order to reduce our indebtedness.

In October 2013, we entered into an agreement to sell all of our oil and natural gas properties located in the Texas Panhandle for $1 billion in cash. The purchase price was adjusted at closing on November 25, 2013 to $944 million in order to, among other things, reflect an economic effective date of October 1, 2013. In addition to the net cash proceeds of $944 million received at closing, $44 million was closed into escrow, which Forest may receive as consents-to-assign are received and post-closing title curative work is completed. Moreover, there is an additional $10 million in escrow that supports post-closing indemnities that we may owe to the buyer under the terms of the purchase and sale agreement. Any of the $10 million remaining in escrow at the one-year anniversary of the closing will be paid to us. As of February 19, 2014, we have received $21 million of the $44 million closed into escrow. We estimated the proved reserves associated with these properties were 517 Bcfe at the time of sale.

In August 2013, we entered into an agreement to sell a portion of our largely undeveloped acreage position located in Crockett County in the Permian Basin of West Texas. This transaction closed on September 10, 2013 and we received net cash proceeds of $31 million.

In January 2013, we entered into an agreement to sell all of our oil and natural gas properties located in South Texas, excluding our Eagle Ford oil properties. This transaction closed on February 15, 2013 and we received net cash proceeds of $321 million. We estimated the proved reserves associated with these properties were 223 Bcfe at the time of sale.

In November 2012, we sold all of our oil and natural gas properties located in South Louisiana for net cash proceeds of $211 million. We estimated the proved reserves associated with these properties were 39 Bcfe at the time of sale. In October 2012, we sold the majority of our East Texas natural gas gathering assets for net cash proceeds of $29 million.

In June 2011, we completed an initial public offering of approximately 18% of the common stock of our then wholly-owned subsidiary, Lone Pine Resources Inc. (“Lone Pine”), which held our ownership interests in our Canadian operations. On September 30, 2011, we distributed, or spun-off, our remaining 82% ownership in Lone Pine to our shareholders, by means of a special stock dividend of Lone Pine common shares. We estimated the proved reserves associated with these properties were 510 Bcfe at the time of spin-off.

In 2009, we sold oil and natural gas properties located in the Permian Basin in West Texas and New Mexico in three separate transactions for net proceeds of $908 million in cash. We estimated the proved reserves associated with these properties were 541 Bcfe at the time of sale.

Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2013, all of which are located in the United States, based on the NYMEX Henry Hub ("HH") price of $3.67 per MMBtu for natural gas and the NYMEX West Texas Intermediate ("WTI") price of $97.33 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, 2013. See "Preparation of Reserves Estimates" below and Note 14 to the Consolidated Financial Statements for additional information regarding our estimated proved reserves.

	Estimated Proved Reserves			
	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Liquids (MBbls)	Total (MMcfe)(1)
Developed	336,342	6,151	6,855	414,378
Undeveloped	118,249	10,523	4,856	210,523
Total estimated proved reserves	454,591	16,674	11,711	624,901

(1) Oil and natural gas liquids are converted to gas-equivalents using a conversion of six Mcf "equivalent" per barrel of oil or natural gas liquids. This conversion is based on energy equivalence and not price equivalence. For 2013, the average of the first-day-of-the-month natural gas price was $3.67 per Mcf, and the average of the first-day-of-the-month oil price was $97.33 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 27 Mcf per barrel of oil and approximately 10 Mcf per barrel of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2013).

As of December 31, 2013, we had estimated proved reserves of 625 Bcfe, a decrease of 54% compared to 1,363 Bcfe of estimated proved reserves at December 31, 2012. During 2013, we added 148 Bcfe of estimated proved reserves through extensions and discoveries primarily driven by our 2013 drilling activity in the Eagle Ford in South Texas and Cotton Valley in East Texas. These reserve additions were offset by property sales of 800 Bcfe and net negative revisions of 10 Bcfe. The net negative revisions of 10 Bcfe were comprised of (i) the reclassification of 41 Bcfe of proved undeveloped reserves ("PUDs") to probable undeveloped reserves for PUDs that are not expected to be developed five years from the time the reserves were initially disclosed, (ii) negative performance revisions of 9 Bcfe, and (iii) positive pricing revisions of 40 Bcfe.

As of December 31, 2013, we had estimated proved undeveloped reserves of 211 Bcfe, or 34% of estimated proved reserves, compared to 425 Bcfe, or 31% of estimated proved reserves as of December 31, 2012. The net decrease of 215 Bcfe was primarily due to property sales including 286 Bcfe of proved undeveloped reserves. During 2013, we invested $75 million to convert 22 Bcfe of our December 31, 2012 PUDs to proved developed reserves. The rate at which we convert PUDs to proved developed reserves has been negatively impacted in the last several years due to our transition away from developing natural gas reserves, many of which were reclassified to probable reserves in the last several years, and towards the development of oil reserves. In connection with this transition, we drilled a high percentage of non-proved locations in an effort to hold leases that would otherwise be lost if instead we were to drill proved undeveloped locations that are on leases already held by producing wells. This trend continued throughout 2013, however, we expect to increase our PUD conversion rate in 2014. As of December 31, 2013, we have no PUDs that have remained undeveloped for five years or more after they were initially disclosed as PUDs.

Preparation of Reserves Estimates

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

Forest's Senior Vice President, Corporate Engineering and Technology, who has held this position since January 2013, has 36 years of experience in oil and gas exploration and production and received a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines. Prior to January 2013, he held positions of increasing responsibility at Forest since joining the company in 2001, including most recently Vice President, Corporate Engineering, a position in which he was also primarily responsible for overseeing the preparation of reserves estimates. Prior to joining Forest, he held various positions in reservoir engineering and corporate planning with Phillips Petroleum, Midcon Exploration, and Apache Corporation.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil, natural gas liquids, and natural gas that cannot be measured in an exact manner, and the accuracy of any reserves estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices or development and production expenses, may require revision of such estimates. Accordingly, oil, natural gas liquids, and natural gas quantities ultimately recovered will vary from reserves estimates. See Part I, Item 1A "Risk Factors" below for a description of some of the risks and uncertainties associated with our business and reserves.

Independent Audit of Reserves

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

For the years ended December 31, 2013, 2012, and 2011, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the year ended December 31, 2013, DeGolyer and MacNaughton independently audited estimates relating to properties constituting over 87% of our reserves by NPV as of December 31, 2013. When compared on a field-by-field basis, some of Forest's estimates of proved reserves were greater and some were less than the estimates prepared by DeGolyer and MacNaughton. However, in the aggregate, Forest's estimates of total proved reserves were within 3% of DeGolyer and MacNaughton's aggregate estimate of proved reserves quantities for the fields audited. The lead technical person at DeGolyer and MacNaughton primarily responsible for overseeing the audit of our reserves received a Bachelor of Science degree in Petroleum Engineering from Texas A&M University, 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 39 years of experience in oil and gas reservoir studies and reserves evaluations.

Drilling Activities

The following table summarizes the number of wells drilled during 2013, 2012, and 2011, all of which are located in the United States, 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, 2013, we had 9 gross (5 net) wells in progress, all of which are located in the United States. During 2013, we drilled a total of 93 gross (45 net) wells, of which 41 were classified as exploratory and 52 were classified as development.

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive(1)	52	23	106	49	101	44
Non-productive(2)	—	—	3	1	—	—
Total development wells	52	23	109	50	101	44
Exploratory wells:						
Productive(1)	40	21	27	24	22	21
Non-productive(2)	1	1	3	3	4	3
Total exploratory wells	41	22	30	27	26	24

(1) A well classified as productive does not always provide economic levels of production.

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

Oil and Natural Gas Wells and Acreage

Productive Wells

The following table summarizes our productive wells as of December 31, 2013, all of which are located in the United States. 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, 2013, we owned interests in 40 gross wells containing multiple completions.

	Gross	Net
Natural Gas	1,432	1,001
Oil	93	68
Total	1,525	1,069

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, 2013. A substantial majority of our developed acreage is subject to mortgage liens securing our bank credit facility. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this summary, as well as acreage related to any options held by us to acquire additional leasehold interests. At December 31, 2013, approximately 36%, 30%, and 16% of our net undeveloped acreage in the United States was held under leases that will expire in 2014, 2015, and 2016, respectively, if not extended by exploration or production activities.

	Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net
United States(1)	239,089	159,927	189,999	121,008
South Africa(2)	—	—	1,235,500	657,286
Italy	—	—	107,043	86,507
Total	239,089	159,927	1,532,542	864,801

(1) Concentrations of net acres in the United States as of December 31, 2013 include: 162,000 net acres in Ark-La-Tex in East Texas, Louisiana, and Arkansas; 24,500 net acres in Eagle Ford; and 63,500 net acres in Permian Basin in West Texas.

(2) In December 2012, we entered into agreements to dispose of our interests in the Block 2A Production Right and the Block 2C Exploration Right in South Africa. The abandonment of the Block 2C Exploration Right was completed in December 2013, with Forest receiving $9 million. The disposal of our interest in the Block 2A Production Right is contingent upon the approval of the government of South Africa, which has not yet occurred. Upon the completion of this transaction, if it occurs, we will no longer hold any acreage in South Africa.

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, 2013, 2012, and 2011 for continuing operations. All of our production occurred in the United States for the years presented and we do not have any fields that individually contain 15% or more of our total estimated proved reserves.

	Year Ended December 31,		
	2013	2012	2011
Liquids:			
Oil and condensate:			
Production volumes (MBbls)	2,271	3,146	2,491
Average sales price (per Bbl)	$96.30	$96.14	$96.22
Natural gas liquids:			
Production volumes (MBbls)	2,521	3,489	3,154
Average sales price (per Bbl)	$29.79	$31.77	$42.91
Total liquids:			
Production volumes (MBbls)	4,792	6,635	5,645
Average sales price (per Bbl)	$61.31	$62.29	$66.43
Natural Gas:			
Production volumes (MMcf)	46,676	81,008	88,497
Average sales price (per Mcf)	$3.16	$2.37	$3.71
Total production volumes (MMcfe)(1)	75,428	120,818	122,367
Average sales price (per Mcfe)	$5.85	$5.01	$5.75
Production costs (per Mcfe):			
Lease operating expenses	$1.02	$.89	$.81
Transportation and processing costs	.16	.12	.11
Production costs excluding production and property taxes (per Mcfe)	1.17	1.02	.92
Production and property taxes	.20	.28	.33
Total production costs (per Mcfe)	$1.37	$1.30	$1.25

(1) Oil and natural gas liquids are converted to gas-equivalents using a conversion of six Mcf "equivalent" per barrel of oil or natural gas liquids. This conversion is based on energy equivalence and not price equivalence. For 2013, the average of the first-day-of-the-month natural gas price was $3.67 per Mcf, and the average of the first-day-of-the-month oil price was $97.33 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 27 Mcf per barrel of oil and approximately 10 Mcf per barrel of NGLs (based on the average of the first-day-of-the-month Mt. Belvieu pricing for NGLs in 2013).

Marketing and Delivery Commitments

Our natural gas production is generally sold on a month-to-month basis in the spot market, priced in reference to published indices. Our oil production is generally sold under short-term contracts at prices based upon refinery postings or NYMEX WTI monthly averages and is typically sold at the wellhead. Our natural gas liquids production is typically sold under term agreements at prices based on postings at large fractionation facilities. We believe that the loss of one or more of our current oil, natural gas, or natural gas liquids purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption. We had no material delivery commitments as of February 19, 2014.

Competition

We encounter intense competition in all aspects of our business, including acquisition of properties and oil and natural gas leases, marketing oil and natural gas, obtaining services, and securing drilling rigs and other equipment necessary for drilling and completing wells. In addition, we compete for people, including experienced geologists, geophysicists, engineers, and other professionals. Our ability to increase production and 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 greater and more productive assets, substantially larger staffs, and greater financial and operational resources than we have. Many of our competitors not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also may have integrated operations that include refining and processing of oil and natural gas products as well as the distribution and marketing of such products. Because of our relatively small size and capital constraints, we may find it increasingly difficult to effectively compete in our markets.

Industry Regulation

Our oil and gas operations are subject to various national, state, and local laws and regulations in the jurisdictions in which we operate. These laws and regulations may be changed in response to economic or political conditions. As a result, our regulatory burden may increase in the future. Laws and regulations have the potential of increasing our cost of doing business and, consequently, could affect our profitability. However, we do not believe that we are affected to a materially greater or lesser extent than others in our industry.

Matters subject to current governmental regulation or pending legislative or regulatory changes include the production, handling, storage, transportation, and disposal of oil and natural gas, by-products from oil and natural gas, and other substances produced or used in connection with oil and natural gas operations. Jurisdictions in which we operate have adopted laws and regulations governing bonding or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, taxation, and the use of derivative hedging instruments. Our operations are also subject to permit requirements for the drilling of wells and regulations relating to the location of wells, the method of drilling and the casing of wells, surface use and restoration of properties on which wells are located, and the plugging and abandonment of wells. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of our operations. At various times, regulatory agencies have imposed price controls and limitations on oil and natural gas production. In order to conserve supplies of oil and natural gas, these agencies may restrict the rates of flow of oil and natural gas wells below actual production capacity. Further, a significant spill from one of our facilities could have a material adverse effect on our results of operations, competitive position, or financial condition. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") imposes reporting and other requirements on our business and operations, including with respect to payments made to U.S. and foreign governments related to our oil and gas exploration and development activities. The legislation also imposes requirements and oversight on our derivatives transactions, including clearing, margin, and position limits requirements. Significant regulations have been promulgated by the SEC, the Commodity Futures Trading

Commission, and other regulatory agencies to implement these requirements and provide certain exemptions for qualified end-users. This legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future. The imposition of these types of requirements or limitations could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activities.

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

Environmental and Climate Change Regulation

We are subject to stringent national, state, and local laws and regulations in the jurisdictions where we operate relating to environmental protection, including the manner in which various substances such as wastes generated in connection with oil and natural gas exploration, production, and transportation operations are managed. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper closure of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of additional compliance costs, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

We currently operate or lease, and have in the past operated or leased, a number of properties that for many years have been used for the exploration and production of oil and natural gas. Although we believe 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, 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 or strict liability without regard to fault or the legality of the original conduct and that could require us to remove previously disposed wastes or remediate property contamination, or to perform well pluggings or pit closures or other actions of a remedial or injunctive nature to prevent future contamination.

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

Hydraulic fracturing is an important process used in the completion of our oil and natural gas wells. The process involves the injection of water, sand, and chemicals under pressure into low-permeability formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. Various state and local governments have implemented, or are considering, increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, control requirements, requirements for disclosure of chemical constituents, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds and in some municipalities. For instance, Texas, Colorado, and Louisiana have adopted far-reaching rules that require the public disclosure of chemicals used in the hydraulic fracturing process, with the Texas rules applicable to fracturing treatments on wells with initial drilling permits issued on or after February 1, 2012, and the Colorado rules applicable to fracturing treatments performed on or after April 1, 2012. The Louisiana regulations require operators to disclose all additives used in hydraulic fracturing fluids and the names and concentrations of chemicals subject to Occupational Safety and Health Administration Hazard Communication requirements that are not deemed a trade secret. The Louisiana requirements are effective for wells with drilling permits issued on or after October 20, 2011. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Several federal entities, including the EPA, also have asserted potential regulatory authority over hydraulic fracturing, and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with the results of the study anticipated to be available for review in 2014. In addition, Congress has considered legislation that would amend the SDWA to encompass all hydraulic fracturing activities. Such a provision would have required hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and record keeping obligations, including disclosure of chemicals used in the fracturing process, and meet plugging and abandonment requirements. If such legislation is adopted in the future, it would establish an additional level of regulation and impose additional costs on our operations. See Part I, Item 1A "Risk Factors—We may incur significant costs related to environmental and other governmental laws and regulations, including those related to "hydraulic fracturing," that may materially affect our operations" and "Recently proposed or finalized rules and guidance imposing more stringent requirements on the oil and gas exploration and production industry could cause us to incur increased capital expenditures and operating costs as well as decrease our levels of production" below.

Nearly half of the states in the U.S., either individually or through multi-state initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases ("GHGs"). Also, the Supreme Court held in Massachusetts, et al. v. EPA (2007) that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act, and subsequently in December 2009, the EPA determined that GHG emissions present an endangerment to public health and the environment because such emissions, according to the EPA, are contributing to warming of the earth's atmosphere and other climate changes. These findings allow the EPA to implement regulations that would restrict GHG emissions under existing provisions of the Clean Air Act. The scope of the EPA's authority to regulate GHG emissions, however, is currently being reviewed by the U.S. Supreme Court, with a decision expected in spring or summer of 2014. On November 8, 2010, the EPA finalized GHG reporting requirements for the petroleum and natural gas industries. Under this final rule, owners or operators of facilities that contain petroleum and natural gas systems, as defined by the rule, and emit 25,000 metric tons or more of GHGs per year per basin (expressed as carbon dioxide equivalents) are to report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. These rules have increased compliance costs on our operations.

We believe 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 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. In addition, some pollution-related risks may not be insurable.

Employees

As of December 31, 2013, we had 363 employees. As of February 19, 2014, we had 223 employees. None of our employees is currently represented by a union for collective bargaining purposes.

10

Geographical Data

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

Offices

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

Title to Properties

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

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Annual Report on Form 10-K. Certain definitions, including the definitions of proved reserves, proved developed reserves, and proved undeveloped reserves, have been abbreviated from the applicable definitions contained in Rule 4-10(a) of Regulation S-X under the Securities Exchange Act of 1934.

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. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface temperature and pressure.

Developed acreage. Acreage that is held by producing wells or wells capable of production.

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

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

11

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, an extension well, a service well, or a stratigraphic test well.

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

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

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

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

HH or Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the NYMEX.

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

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

Liquids. Oil, condensate, and natural gas liquids.

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

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

Mcf. Thousand cubic feet of natural gas.

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

MMBtu. One million British Thermal Units.

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 or natural gas liquids. Liquid hydrocarbons found in natural gas which may be extracted as separate components, including ethane, propane, butanes, and natural gasoline.

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

NYMEX. New York Mercantile Exchange.

Productive wells. Producing wells and wells that are mechanically capable of production.

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

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

Proved undeveloped reserves or PUDs. 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 recompletion.

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

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

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

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

WTI or West Texas Intermediate. A grade of crude oil used as a benchmark in oil pricing.

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 the Audit, Compensation, and Nominating and Corporate Governance committees of our Board of Directors, and codes of ethics for our directors and employees entitled “Code of Business Conduct and Ethics” and “Proper Business Practices Policy,” respectively.

Forward-Looking Statements

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

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

- estimates of our oil and natural gas reserves;
- operational initiatives and their effect on our production, expenses, and reserves;
- estimates of our future oil and natural gas production, including estimates of any increases or decreases in our production, and the liquids/natural gas mix of that 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 natural gas prices;
- the amount, nature, and timing of future capital expenditures, including future development costs;
- our ability to access the capital markets to fund capital and other expenditures;
- our assessment of our counterparty risk and the ability of our counterparties to perform their future obligations; and
- the impact of federal, state, and local political, regulatory, and environmental developments in the United States and certain foreign locations where we conduct business operations.

We believe the expectations, estimates, projections, beliefs, forecasts, and assumptions reflected in our forward-looking statements are reasonable, but we can give no assurance that they will prove to be correct. We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, and sale of oil and natural gas. See “Competition,” “Industry Regulation,” and “Environmental and Climate Change Regulation” above, as well as Part I, Item 1A “Risk Factors,” Part II, Item 7 “Management’s

Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources," and Part II, Item 7A "Quantitative and Qualitative Disclosures about Market Risk" for a description of various, but by no means all, factors that could materially affect our ability to achieve the anticipated results described in the forward-looking statements.

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

Item 1A. Risk Factors.

We are subject to certain risks and hazards due to the nature of the business activities we conduct. 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. Except where the context otherwise indicates, references to oil and natural gas in this section include natural gas liquids.

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

Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to a variety of factors that are beyond our control. Approximately 73% of our estimated proved reserves at December 31, 2013 were natural gas, causing us to be particularly dependent on prices for natural gas. Low commodity prices may mean that it will not be economical to drill or produce oil and natural gas from some of our existing properties, and we may be required to curtail, or stop completely, our production activities in those areas. A decline in commodity prices may have numerous effects on our business, including the following:

- impairing our financial condition, liquidity, or ability to fund planned capital expenditures;

- limiting our access to sources of capital, such as equity and debt;

- prohibiting us from developing our current properties, or from growing our asset base; or

- making it more difficult to pay interest and principal on our indebtedness and satisfy our other obligations.

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

As of December 31, 2013 and February 19, 2014, we had a principal amount of long-term indebtedness of $800 million.

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

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

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

- limit our access to the capital markets;

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

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

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

A higher level of debt increases 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, natural gas, and natural gas liquids prices, financial, business, domestic, and global economic conditions, governmental regulations and environmental regulations, and other factors, including the mix and quality of our assets and our ability to develop and produce them. Many of these factors are beyond our control.

Over the past few years we have sold a significant amount of developed and undeveloped assets, and used the proceeds to reduce outstanding indebtedness. Despite these efforts, our debt remains relatively high in comparison to our remaining operating cash flows and assets. Our cash flows from our remaining assets may not be sufficient to service our debt and other obligations or to meet the financial or other restrictive covenants contained in our bank credit facility and the indentures governing our outstanding senior notes. As a result, we may be required, if possible, to refinance or restructure the debt, sell additional assets, or sell shares of our common or preferred equity securities — all on terms that we do not find attractive. We also may be required to reduce expenses by curtailing operations.

The governing documents of our debt instruments contain covenants and restrictions that require us to meet certain financial tests and place restrictions on the incurrence of additional indebtedness. A failure on our part to comply with the financial and other restrictive covenants contained in our bank credit facility and the indentures governing our outstanding senior notes could result in a default under these agreements. Any default under our bank credit facility 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, if not waived by the relevant lenders, a default could lead to foreclosure of our assets, which in turn could result in bankruptcy.

We may not be able to obtain funding under our current bank credit facility because of a decrease in our borrowing base or obtain funding in the capital markets on terms we find acceptable.

Historically, we have used our cash flows from operations and borrowings under our bank credit facility to fund our capital expenditures and have relied on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions or to refinance debt obligations. We currently have a bank credit facility with lender commitments totaling $1.5 billion. The borrowing base is determined by the lenders periodically and is based on the estimated value of our properties using pricing models determined by the lenders at such time. The current borrowing base was set at $400 million in connection with the closing of the sale of our assets in the Texas Panhandle on November 25, 2013. The next scheduled redetermination of the borrowing base will occur on or before May 1, 2014, at which time our borrowing base may be further reduced. Also, under the terms of our bank credit facility, our borrowing base will be immediately decreased by an amount equal to 25% of the stated principal amount of senior notes issued in the future (excluding any senior notes that we may issue to refinance senior notes that were outstanding on June 30, 2011). In the future, we may not be able to access adequate funding under our bank credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. Since the process for determining the borrowing base under our bank credit facility involves evaluating the estimated value of our oil and natural gas properties using pricing models determined by the lenders at that time, a decline in those prices used, or further downward reductions of our reserves, likely will result in a redetermination of our borrowing base and a decrease in the available borrowing amount at the time of the next scheduled redetermination. In such case, we would be required to repay any indebtedness in excess of the borrowing base.

Volatility in the public and private capital markets may make it more difficult to obtain funding. There is a risk that the cost of obtaining money from the credit markets may increase in the future as lenders and institutional investors may increase interest rates, impose tighter lending standards, refuse to refinance existing debt at maturity on terms similar to existing debt or at all, or reduce or cease to provide any new funding. Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Our debt agreements contain restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities.

Our bank credit facility and the indentures governing our senior notes contain restrictive covenants that limit our ability and the ability of certain of our subsidiaries to, among other things:

- incur or guarantee additional indebtedness or issue preferred shares;

- pay dividends or make other distributions;

- purchase equity interests or redeem subordinated indebtedness early;

- create or incur certain liens;

- enter into transactions with affiliates; and

- sell assets or merge or consolidate with another company.

Complying with the restrictions contained in some of these covenants will require us to meet certain financial ratios and tests, notably with respect to consolidated interest coverage, total assets, net debt, equity, and net income. For example, our bank credit facility provides that we will not permit our ratio of total debt to EBITDA (as adjusted for non-cash charges) calculated for the preceding four consecutive fiscal quarter period then most recently ended to be greater than a specified amount. In September 2013, we amended the facility to increase the permitted ratio to 5.0 to 1.0 for any time after September 11, 2013 up to and including March 31, 2014, and to 4.75 to 1.0 for any time after April 1, 2014 up to and including June 30, 2014. After June 30, 2014, the ratio returns to the original restriction of 4.5 to 1.0. Our ratio of total debt to EBITDA for the four consecutive fiscal quarter period ending December 31, 2013, as calculated in accordance with our bank credit facility, was 4.3. Our need to comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures, or withstand a future downturn in our business. Based on our current projections, absent an amendment to the bank credit facility, we expect the ratio of total debt to EBITDA to exceed the maximum allowed sometime during the second or third quarter of 2014. Non-compliance with the terms of our debt covenants or other credit provisions could result in all amounts outstanding under our bank credit facility and, potentially, our indentures, becoming due and payable immediately, and the resultant termination of our bank credit facility. This would result, at a minimum, in the need to slow or cease the incurrence of capital and operational expenditures, which would have a negative impact on our expected production, revenues and, potentially, on our reserves. At worse, it could also result in foreclosure of our assets and potential bankruptcy. See Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" for a more complete discussion of our debt obligations and liquidity.

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

Compared to many of our competitors in the oil and gas industry, we are a very small company. We face difficulties in competing with larger companies. The costs of doing business in the exploration and production industry, including such costs as those required to explore new oil and natural gas plays, to acquire new acreage, and to develop attractive oil and natural gas projects, are significant. We face intense competition in all areas of our business from companies with greater and more productive assets, substantially larger staffs, and greater financial and operating resources than we have. In addition, legacy costs associated with our relatively long period of existence may result in our operating costs being greater than competitors of similar size. Our limited size has placed us at a disadvantage with respect to funding our operating costs, and means that we are more vulnerable to commodity price volatility and overall industry cycles, are less able to absorb the burden of changes in laws and regulations, and that poor results in any single exploration, development, or production play can have a disproportionately negative impact on us.

We also compete for people, including experienced geologists, geophysicists, engineers, and other professionals. Our limited size has placed us at a disadvantage with respect to attracting and retaining management and other professionals with the technical abilities necessary to successfully operate our business. For instance, since the beginning of 2013 alone, three executive officers resigned their positions with Forest, and Forest's employee resignation rate was 16% per annum versus the historic norm of 10%. Continued difficulty in retaining quality personnel may have a negative impact on our operations.

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

The proved oil and natural gas reserves information and the related future net revenues information included in this Annual Report on Form 10-K and in our other periodic reports represent only estimates, which are prepared by our internal staff of engineers and the majority of which are audited by DeGolyer and MacNaughton, an independent petroleum engineering firm. Estimating quantities of proved oil and natural gas reserves is a complex, inexact process and depends on a number of interpretations of technical data and various factors and assumptions, including assumptions required by the SEC as to oil, natural gas, and natural gas liquids prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds. As a result, these estimates are inherently imprecise. Any significant inaccuracies or changes in our assumptions or changes in operating conditions could cause the estimated quantities and net present value of the estimated reserves to be significantly different.

At December 31, 2013, approximately 34% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserves estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule, and results associated with these properties may not be as estimated.

Our estimated proved reserves as of December 31, 2013 were based on a NYMEX HH price of $3.67 per MMBtu for natural gas and a NYMEX WTI price of $97.33 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, 2013, and an average realization for a barrel of natural gas liquids during that period equal to approximately 31% of the NYMEX WTI price or $29.93. For the year ended December 31, 2012, the comparable prices used to calculate our estimated proved reserves were $2.76 per MMBtu for natural gas, $94.79 per barrel for oil, and an average realization for a barrel of natural gas liquids equal to approximately 36% of the oil price or $33.83. Despite the increase in prices from those used to estimate proved reserves as of December 31, 2012, which resulted in positive reserve revisions of 40 Bcfe during 2013, we revised our estimated proved reserves downward during 2013 by 41 Bcfe due to the reclassification of proved undeveloped reserves ("PUDs") to probable undeveloped reserves for PUDs that are not expected to be developed five years from the time the reserves were initially disclosed and by 9 Bcfe due to negative performance revisions. We may be required to make further downward revisions in our proved reserves in the future. You should not assume that any present value of future net cash flows from our estimated proved reserves as set forth in this Annual Report on Form 10-K for the year ended December 31, 2013 represents the market value of our oil and natural gas reserves.

Lower oil, natural gas, and natural gas liquids 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 natural gas activities. Under this method, we capitalize the cost to acquire, explore for, and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and natural 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 natural 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 does not impact cash flows from operating activities, but it does reduce our shareholders' equity.

Investments in unproved properties also are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. 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 is added to the costs to be amortized, the amount by which the ceiling limit exceeds the capitalized costs of proved oil and natural gas properties is 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 decline in our market capitalization relative to our net asset values or other adverse economic or qualitative factors.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil, natural gas, and natural gas liquids prices are low. In addition, write-downs may occur if we experience downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development or operating costs increase. For example, during 2013 we incurred a ceiling test write-down of $58 million. Additional write-downs of the United States cost center may be required in subsequent periods if, among other things, the unweighted arithmetic average of the first-day-of-the-month oil, natural gas, and natural gas liquids prices used in the calculation of the present value of future net revenue from estimated production of estimated proved reserves decline compared to prices used as of December 31, 2013, unproved property values are impaired, estimated proved reserve volumes are revised downward, or costs incurred in exploration, development, or acquisition activities exceed the discounted future net cash flows from the additional reserves, if any, attributable to the cost center.

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

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

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

19

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

Approximately 43% of our net acreage located in the United States is currently undeveloped. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans are subject to change based upon various factors, including drilling results, oil and natural gas prices, cash flow, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. We cannot be sure that we will be able to maintain all of our leased properties by initiating production. Any such loss of properties could reduce our access to capital and have a negative impact on our operations.

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

We deliver the majority of our oil and natural gas through gathering facilities that we do not own or operate. As a result, we are subject to the risk that these facilities may be temporarily unavailable due to mechanical reasons or market conditions, or may not be available to us in the future. These issues can result in wells being shut in or in us receiving lower prices for our production. If we experience interruptions or loss of pipeline capacity or access to gathering systems that impact a substantial amount of our production, it could have an adverse impact on our operations and cash flow. We are subject to similar risks with respect to processing facilities and other midstream infrastructure and services.

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

Drilling activities are subject to many risks, including well blow-outs, cratering and explosions, pipe failures, fires, uncontrollable flows of oil, natural gas, brine, or well fluids, other environmental hazards, and risks outside of our control, including, among other things, the risk of natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources, and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. We maintain insurance against some, but not all, of the risks described above. Generally, pollution-related environmental risks are not fully insurable. We do not insure against business interruption. We cannot assure that our insurance will be fully adequate to cover other losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

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

We periodically enter into hedging agreements for a portion of our anticipated oil, natural gas, and natural gas liquids production. Our commodity hedging agreements are limited in duration, usually for periods of one year or less; however, we sometimes enter into hedges for longer periods. Should commodity prices increase after we have entered into a hedging transaction, our cash flows will be lower than they would have been without the hedging transaction.

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

Moreover, our hedging program may be limited due to certain regulatory constraints. The Dodd-Frank Wall Street Reform and Consumer Protection Act, among other things, imposes requirements and oversight on hedging transactions, including clearing and margin requirements under certain circumstances. While certain of the implementing regulations are yet to be finalized by the relevant federal agencies, to the extent that they are applicable to us or our counterparties, we may incur increased costs and cash collateral requirements that could affect our ability to hedge risks associated with our business.

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

Our oil and natural gas operations are subject to various U.S. federal, state, and local laws and regulations, and local and national laws and regulations in Italy and South Africa. Many of the laws and regulations to which our operations are subject include those relating to the protection of the environment. We could incur material costs, including clean-up costs, fines, and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, present or future environmental laws and regulations.

We routinely utilize hydraulic fracturing, which is an important and common practice used to stimulate production of hydrocarbons from tight or low-permeability formations. State oil and gas commissions typically regulate the process. However, several federal entities, including the EPA, have also recently asserted potential regulatory authority over hydraulic fracturing. Most notably, the EPA is conducting a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. A draft report is expected sometime in 2014. Some states, such as Texas, have adopted, and some states, including others in which we operate, are considering adopting, regulations that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing operations. Some local governmental bodies have adopted or are considering adopting similar regulations. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to operate. Restrictions on, or increased costs of, hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Recently proposed or finalized rules and guidance imposing more stringent requirements on the oil and gas exploration and production industry could cause us to incur increased capital expenditures and operating costs as well as decrease our levels of production.

Federal, state, and local regulatory developments could adversely impact our operations in a variety of ways, including by causing us to incur increased capital expenditures and costs. For example, on April 17, 2012, the EPA approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”) and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks, and other production equipment. The EPA currently is reconsidering parts of these air rules, with expected finalization in November 2014. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

In addition, federal agencies have recently announced at least two other regulatory initiatives regarding certain aspects of hydraulic fracturing that could further increase our costs to operate and decrease our levels of production. On May 4, 2012, the U.S. Department of the Interior (“DOI”) announced proposed rules that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon federal and Indian lands and also would strengthen standards for well-bore integrity and the management of fluids that return to the surface during and after fracturing operations on federal and Indian lands. The DOI has not yet finalized these rules. Also on May 4, 2012, the EPA issued draft guidance for federal Safe Drinking Water Act permits issued to oil and natural gas exploration and production operators using diesel during hydraulic fracturing. The EPA has not yet finalized this guidance. The adoption or implementation of these regulatory initiatives could cause us to incur increased expenditures and decrease our levels of production.

The credit risk of financial institutions could adversely affect us.

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

Item 1B. Unresolved Staff Comments.

As of December 31, 2013, we did not have any SEC staff comments regarding our periodic or current reports that have been unresolved for 180 days or more.

Item 2. Properties.

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

Item 3. Legal Proceedings.

On February 29, 2012, two members of a three-member arbitration panel reached a decision adverse to Forest in the proceeding styled Forest Oil Corp., et al. v. El Rucio Land & Cattle Co., et al., which occurred in Harris County, Texas. The third member of the arbitration panel dissented. The proceeding was initiated in January 2005 and involves claims asserted by the landowner-claimant based on the diminution in value of its land and related damages allegedly resulting from operational and reclamation practices employed by Forest in the 1970s, 1980s, and early 1990s. The arbitration decision awards the claimant $23 million in damages and attorneys' fees and additional injunctive relief regarding future surface-use issues. On October 9, 2012, after vacating a portion of the decision imposing a future bonding requirement on Forest, the trial court for the 55th Judicial District, in the District Court in Harris County, Texas, reduced the arbitration decision to a judgment. Forest is seeking to have this judgment reversed on appeal and believes it has meritorious arguments in support thereof.

On May 25, 2012, a lawsuit, styled Augenbaum v. Lone Pine Resources Inc. et al., was brought as a purported class action in the Supreme Court of the State of New York, New York County against Forest, Lone Pine, certain of Lone Pine's current and former directors and officers (the "Individual Defendants"), and certain underwriters (the "Underwriter Defendants") of Lone Pine's initial public offering (the "IPO"), which was completed on June 1, 2011. The complaint alleges that Lone Pine's registration statement and prospectus issued in connection with the IPO contained untrue statements of material fact or omitted to state material facts relating to forest fires that occurred in Northern Alberta in May 2011, the rupture of a third-party oil sales pipeline in Northern Alberta in April 2011, and the impact of those events on Lone Pine, that the alleged misstatements or omissions violated Section 11 of the Securities Act, and that Lone Pine, the Individual Defendants, and the Underwriter Defendants are liable for such violations. (The complaint was subsequently amended to drop the allegation regarding the forest fires.) The complaint further alleges that the Underwriter Defendants offered and sold Lone Pine's securities in violation of Section 12(a)(2) of the Securities Act, and the putative class members seek rescission of the securities purchased in the IPO that they continue to own and rescissionary damages for securities that they have sold. Finally, the complaint asserts a claim against Forest under Section 15 of the Securities Act, alleging that Forest was a "control person" of Lone Pine at the time of the IPO. The complaint alleges that the putative class, which purchased shares of Lone Pine's common stock pursuant and/or traceable to Lone Pine's registration statement and prospectus, was damaged when the value of the stock declined in August 2011. The complaint does not specify the amount of such damages. Forest believes that these claims are without merit and intends to defend the claim against it vigorously.

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

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

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, 2014, our Common Stock was held by 587 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 2012 or 2013. On February 19, 2014, the closing price of Forest Common Stock was $3.22.

		Common Stock	
		High	Low
2012	First Quarter	$15.15	$11.61
	Second Quarter	13.69	6.22
	Third Quarter	9.32	5.68
	Fourth Quarter	9.12	6.06
2013	First Quarter	$7.44	$5.18
	Second Quarter	5.43	3.77
	Third Quarter	6.67	4.02
	Fourth Quarter	6.52	3.43

Dividend Restrictions

Forest's present or future ability to pay dividends is governed by (i) the provisions of the New York Business Corporation Law, (ii) Forest's Restated Certificate of Incorporation and Bylaws, (iii) the indentures governing Forest's 7¼% senior notes due 2019 and 7½% senior notes due 2020 and (iv) Forest's bank credit facility dated as of June 30, 2011, as amended. The provisions in the indentures pertaining to these senior notes and in the bank credit facility limit our ability to make restricted payments, which include dividend payments. On September 30, 2011, Forest distributed a special stock dividend in connection with the spin-off of Lone Pine; however, Forest has not paid cash dividends on its Common Stock during the past five years. The future payment of cash dividends, if any, on the Common Stock is within the discretion of the Board of Directors and will depend on Forest's earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that Forest will pay any cash dividends. For further information regarding our equity securities, our ability to pay

23

dividends on our Common Stock, and the spin-off of Lone Pine, see Notes 3 and 5 to the Consolidated Financial Statements.

Unregistered Sales of Equity Securities

We did not make any sales of unregistered equity securities during the quarter ended December 31, 2013.

Issuer Purchases of Equity Securities

The table below sets forth information regarding repurchases of our Common Stock during the quarter ended December 31, 2013. The shares repurchased represent shares of our Common Stock that employees elected to surrender to Forest to satisfy their tax withholding obligations upon the vesting of shares of restricted stock. Forest does not consider this a share buyback program.

Period	Total # of Shares Purchased	Average Price Per Share	Total # of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum # (or Approximate Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs
October 2013	89,653	$5.35	—	—
November 2013	40,612	4.29	—	—
December 2013	3,116	3.76	—	—
Fourth Quarter Total	133,381	$4.99	—	—

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2008 (and the reinvestment of dividends thereafter) in each of Forest Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. We believe that the Dow Jones U.S. Exploration and Production Index is meaningful because it is an independent, objective view of the performance of other similarly-sized energy companies.

Comparison Of 5 Year Cumulative Total Return*
Among Forest Oil Corporation, the S&P 500 Index,
and the Dow Jones US Exploration & Production Index

*$100 invested on 12/31/08 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

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

Item 6. Selected Financial Data.

The following table sets forth selected financial and operating data of Forest as of and for each of the years in the five-year period ended December 31, 2013. This data should be read in conjunction with Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto contained elsewhere in this report. We have completed several oil and gas property divestitures that affect the comparability of the results for the years presented below. See Part I, Item 1 "Business—Acquisition and Divestiture Activities" and Note 2 to the Consolidated Financial Statements for more information on divestitures.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Oil, natural gas, and natural gas liquids sales[1]	$441,341	$605,523	$703,531	$707,692	$655,579
Net earnings (loss) from continuing operations	$73,924	$(1,288,931)	$98,260	$189,662	$(793,789)
Net earnings (loss) from discontinued operations[2]	—	—	44,569	37,859	(129,344)
Net earnings (loss)	73,924	(1,288,931)	142,829	227,521	(923,133)
Less: net earnings attributable to noncontrolling interest[2]	—	—	4,987	—	—
Net earnings (loss) attributable to Forest Oil Corporation common shareholders	$73,924	$(1,288,931)	$137,842	$227,521	$(923,133)
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:					
Earnings (loss) from continuing operations	$.62	$(11.21)	$.86	$1.68	$(7.61)
Earnings (loss) from discontinued operations	—	—	.35	.33	(1.24)
Basic earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$.62	$(11.21)	$1.21	$2.01	$(8.85)
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders:					
Earnings (loss) from continuing operations	$.62	$(11.21)	$.85	$1.67	$(7.61)
Earnings (loss) from discontinued operations	—	—	.34	.33	(1.24)
Diluted earnings (loss) per common share attributable to Forest Oil Corporation common shareholders	$.62	$(11.21)	$1.19	$2.00	$(8.85)
Total assets[1]	$1,117,952	$2,201,862	$3,381,151	$3,070,197	$3,169,054
Long-term debt[1]	$800,179	$1,862,100	$1,693,044	$1,869,372	$2,022,514
Shareholders' equity (deficit)	$54,469	$(42,824)	$1,193,113	$1,352,787	$1,079,154

OPERATING DATA[(1)]					
Annual production:					
Oil (MBbls)	2,271	3,146	2,491	2,357	3,397
Natural gas (MMcf)	46,676	81,008	88,497	101,346	116,029
NGLs (MBbls)	2,521	3,489	3,154	3,589	3,012
Average sales price:					
Oil (per Bbl)	$96.30	$96.14	$96.22	$76.08	$56.87
Natural gas (per Mcf)	$3.16	$2.37	$3.71	$3.99	$3.33
NGLs (per Bbl)	$29.79	$31.77	$42.91	$34.54	$25.17

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

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

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

All expectations, forecasts, assumptions, and beliefs about our future financial results, condition, operations, strategic plans, and performance are forward-looking statements, as described in more detail in Part I, Item 1 under the heading "Forward-Looking Statements." Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed in Part I, Item 1A "Risk Factors," and elsewhere in this Annual Report on Form 10-K. Historical statements made herein are accurate only as of the date of filing of this Annual Report on Form 10-K with the SEC, and may be relied upon only as of that date. The following discussion and analysis should be read in conjunction with Forest's Consolidated Financial Statements and Notes thereto.

Forest is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Our total estimated proved reserves as of December 31, 2013 were approximately 625 Bcfe, all of which are located in our one reportable geographical segment - the United States. Our core operational areas are in Eagle Ford in South Texas and Ark-La-Tex in Texas, Louisiana, and Arkansas. See Item 1 "Business" for a discussion of our business strategy and core operational areas of focus.

2013 Highlights

Forest's 2013 highlights were as follows:

- Reduced the outstanding principal of our long-term debt by $1.1 billion.

- Received cash proceeds of $1.3 billion from the property divestiture program we initiated in 2012, including $321 million for the South Texas divestiture and $965 million for the Panhandle divestiture.

- Increased total oil and NGL sales volumes to 38% of total equivalent sales volumes compared to 33% in 2012 and 28% in 2011. Pro forma for property divestitures in 2012 and 2013, total oil and NGL sales volumes were 29% of total equivalent sales volumes in 2013 compared to 19% in 2012.

- Entered into an agreement with a third-party for the development of our Eagle Ford acreage in South Texas. Under the terms of the agreement, the third-party will pay a $90 million drilling carry in exchange for a 50% working interest in our Eagle Ford acreage position. We are the operator of the drilling program. As of December 31, 2013, we had realized $61 million of the drilling carry.

- Increased Eagle Ford average net sales volumes by 62% over 2012 to approximately 2,550 boe/d.

- Reduced drilling and completion costs per well in the Eagle Ford by 15% over 2012.

Results of Operations

Forest recorded net earnings in 2013 of $74 million as compared to a net loss of $1.3 billion in 2012. Net earnings in 2013 included a $193 million net gain recognized on the sale of our assets in the Texas Panhandle, a $49 million loss on the early extinguishment of debt, $31 million in unrealized losses on derivative instruments, and a $58 million ceiling test write-down. The net loss in 2012 was primarily due to ceiling test write-downs and other non-cash property impairments totaling $1.1 billion as well as a $245 million valuation allowance placed against net deferred tax assets primarily as a result of the ceiling test write-downs and property impairments recognized in 2012. See "Critical Accounting Policies, Estimates, Judgments and Assumptions—Valuation of Deferred Tax Assets" for further discussion of our valuation allowance. The 2012 net loss also included $39 million in unrealized losses on derivative instruments and a $36 million loss on the early extinguishment of debt.

Adjusted EBIDTA, which is a performance measure not calculated in accordance with generally accepted accounting principles ("GAAP"), is commonly used by management, securities analysts, and investors and excludes non-cash items such as depletion expense, deferred income tax expense, and ceiling test write-downs. Our Adjusted EBITDA was $333 million in 2013 as compared to $514 million in 2012. The decrease of $181 million was primarily attributable to property divestitures during 2013, which reduced revenues and, to a lesser extent, reduced production expense. See "Reconciliation of Non-GAAP Measure" at the end of this Item 7 for a reconciliation of Adjusted EBITDA to net earnings (loss) from continuing operations, the most directly comparable financial measure calculated and presented in accordance with GAAP.

During 2013, we completed two large oil and natural gas property divestitures, as discussed in Part I, Item 1 "Business—Acquisition and Divestiture Activities" and Note 2 to the Consolidated Financial Statements. Because of these divestitures, we anticipate that our 2014 oil, natural gas, and natural gas liquids sales volumes, revenues, and production expense will be lower as compared to 2013. Additionally, we expect 2014 interest expense and general and administrative expense to be lower as compared to 2013 due to less debt and fewer employees, respectively.

Oil, Natural Gas, and Natural Gas Liquids Volumes and Revenues

Oil, natural gas, and natural gas liquids sales volumes, revenues, and average sales prices from continuing operations for the years ended December 31, 2013, 2012, and 2011, are set forth in the table below.

	Year Ended December 31,		
	2013	2012	2011
Sales volumes:			
Oil (MBbls)	2,271	3,146	2,491
Natural gas (MMcf)	46,676	81,008	88,497
NGLs (MBbls)	2,521	3,489	3,154
Totals (MMcfe)	75,428	120,818	122,367
Revenues (in thousands):			
Oil	$218,704	$302,445	$239,695
Natural gas	147,530	192,220	328,510
NGLs	75,107	110,858	135,326
Totals	$441,341	$605,523	$703,531
Average sales price per unit:			
Oil ($/Bbl)	$96.30	$96.14	$96.22
Natural gas ($/Mcf)	3.16	2.37	3.71
NGLs ($/Bbl)	29.79	31.77	42.91
Totals ($/Mcfe)	$5.85	$5.01	$5.75

Equivalent sales volumes were 75.4 Bcfe in 2013 as compared to 120.8 Bcfe in 2012. The 38% decrease in equivalent sales volumes in 2013 compared to 2012 was primarily due to divestitures of producing oil and natural gas properties in South Louisiana, South Texas, and the Texas Panhandle, which occurred in November 2012, February 2013, and November 2013, respectively. The decreases due to asset sales were partially offset by an increase in oil production primarily from our Eagle Ford operations in South Texas. Revenues from oil, natural gas, and NGLs were $441 million in 2013 as compared to $606 million in 2012. The $164 million decrease was primarily the result of the net decrease in equivalent sales volumes, which was partially offset by a 17% increase in the average sales price per Mcfe between the two periods from $5.01 per Mcfe in 2012 to $5.85 per Mcfe in 2013.

Equivalent sales volumes from continuing operations decreased 1% in 2012 compared to 2011. Revenues from oil, natural gas, and NGLs were $606 million in 2012 as compared to $704 million in 2011. The $98 million decrease was primarily the result of the decline in the market price for natural gas and NGLs, partially offset by the increase in oil sales volumes.

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

Production Expense

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

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands, Except per Mcfe Data)		
Production expense:			
Lease operating expenses	$76,675	$108,027	$99,158
Production and property taxes	14,857	34,249	40,632
Transportation and processing costs	11,895	14,633	13,728
Production expense	$103,427	$156,909	$153,518
Production expense per Mcfe:			
Lease operating expenses	$1.02	$.89	$.81
Production and property taxes	.20	.28	.33
Transportation and processing costs	.16	.12	.11
Production expense per Mcfe	$1.37	$1.30	$1.25

Lease Operating Expenses

Lease operating expenses in 2013 were $77 million, or $1.02 per Mcfe, compared to $108 million, or $.89 per Mcfe, in 2012. Lease operating expenses decreased $31 million in 2013 compared to 2012 due to the oil and natural gas property divestitures that occurred in November 2012, February 2013, and November 2013. The increase in per-unit lease operating expenses is primarily due to a higher percentage of oil production as a percentage of total equivalent production. Based on the energy-equivalent ratio of six Mcf of natural gas to one barrel of oil, oil production typically has higher per-unit lease operating costs than does natural gas production. However, because the market price of oil relative to natural gas is currently well in excess of the six-to-one ratio, the increase in lease operating expense associated with an increase in oil production is more than offset by the additional revenues realized from oil sales.

Lease operating expenses were $108 million, or $.89 per Mcfe, in 2012 compared to $99 million, or $.81 per Mcfe, in 2011. The increase in total and per-unit lease operating expenses was primarily due to increases in water disposal costs and workovers as well as an increase in oil production.

Production and Property Taxes

Production and property taxes, consisting primarily of severance taxes paid on the value of the oil, natural gas, and NGLs sold, were 3.4%, 5.7%, and 5.8% of oil, natural gas, and NGL sales for the years ended December 31, 2013, 2012, and 2011, respectively. The decreases in production and property taxes as a percentage of

revenues in 2013 compared to prior years were due to the November 2012 sale of the South Louisiana properties, which had higher associated production tax rates.

Transportation and Processing Costs

Transportation and processing costs were $12 million, or $.16 per Mcfe, in 2013, $15 million, or $.12 per Mcfe, in 2012, and $14 million, or $.11 per Mcfe, in 2011. The decrease in total transportation and processing costs in 2013 as compared to 2012 is due to the oil and natural gas property divestitures. However, the per-unit amount increased in 2013 as compared to 2012 due primarily to increased trucking charges for our oil production.

General and Administrative Expense

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

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands, Except Per Mcfe Data)		
Stock-based compensation costs	$18,592	$22,897	$35,706
Stock-based compensation costs capitalized	(7,808)	(7,378)	(14,886)
	10,784	15,519	20,820
Other general and administrative costs	70,227	74,149	75,792
Other general and administrative costs capitalized	(26,185)	(30,406)	(31,507)
	44,042	43,743	44,285
General and administrative expense	$54,826	$59,262	$65,105

General and administrative expense was $55 million in 2013 compared to $59 million and $65 million in 2012 and 2011, respectively. For the year ended December 31, 2013, other general and administrative costs include $14 million ($11 million net of capitalized amounts) in employee-related asset divestiture costs, and stock-based compensation costs include $5 million ($2 million net of capitalized amounts) in accelerated stock-based compensation costs. These costs are associated with the sale of our South Texas and Panhandle oil and natural gas properties during the first and fourth quarters of 2013, respectively. For the year ended December 31, 2012, stock-based compensation costs include $5 million ($4 million net of capitalized amounts) in accelerated stock-based compensation costs, and other general and administrative costs include $2 million ($2 million net of capitalized amounts) in severance costs, both of which are related to the termination of our former chief executive officer. For the year ended December 31, 2011, $12 million in stock-based compensation costs ($7 million net of capitalized amounts) were recognized related to the spin-off of Lone Pine, which caused the forfeiture restrictions to lapse on a portion of each outstanding restricted stock award, thus requiring the immediate recognition of compensation cost. The percentage of general and administrative costs capitalized remained consistent between the three years presented, ranging between 38% and 42%.

Depreciation, Depletion, and Amortization

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

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands, Except Per Mcfe Data)		
Depreciation, depletion, and amortization expense	$171,557	$280,458	$219,684
Depreciation, depletion, and amortization expense per Mcfe	$2.27	$2.32	$1.80

Depreciation, depletion, and amortization expense ("DD&A") decreased $.05 per Mcfe to $2.27 per Mcfe in 2013 compared to $2.32 per Mcfe in 2012. DD&A was $2.32 per Mcfe in 2012 compared to $1.80 per Mcfe in 2011. The decrease in DD&A from 2012 to 2013 was due primarily to oil and natural gas property divestitures, partially offset by oil reserve additions, which typically have higher per-unit development costs than natural gas reserves. The increase in DD&A from 2011 to 2012 was due primarily to the increase in oil reserve additions. In addition, in 2012, a significant portion of our proved undeveloped natural gas reserves, which have lower associated development costs than proved undeveloped oil reserves, were reclassified from proved to probable status in conjunction with the decrease in the natural gas prices used to determine our proved reserves.

Ceiling Test Write-Down of Oil and Natural Gas Properties

At December 31, 2013, we recorded a ceiling test write-down of our United States cost center totaling $58 million, pursuant to the ceiling test limitation prescribed by the SEC for companies using the full cost method of accounting. This ceiling test write-down was primarily a result of the Panhandle divestiture in the fourth quarter of 2013. Given the magnitude of the Panhandle oil and natural gas reserves as a percentage of our total reserves, the divestiture resulted in a $193 million net gain on disposition of assets rather than 100% of the divestiture proceeds reducing capitalized costs, as has typically been done with previous sales of oil and natural gas properties. This smaller reduction of capitalized costs and the loss of future net revenues from the divested proved oil and natural gas reserves were the primary factors causing the ceiling test write-down. Additional write-downs of our oil and natural gas properties may be required in subsequent periods if, among other things, the unweighted arithmetic average of the first-day-of-the-month oil, natural gas, or NGL prices used in the calculation of the present value of future net revenues from estimated production of proved oil and natural gas reserves declines compared to prices used as of December 31, 2013, unproved properties are impaired, estimated proved reserve volumes are revised downward, or costs incurred in exploration, development, or acquisition activities exceed the discounted future net cash flows from the additional reserves, if any, attributable to the cost center. See "Critical Accounting Policies, Estimates, Judgments and Assumptions—Full Cost Method of Accounting" for more information regarding ceiling test write-downs.

In 2012, we recorded ceiling test write-downs of our United States cost center totaling $958 million and our Italian cost center totaling $35 million. The United States write-downs were primarily a result of the decline in the twelve-month arithmetic average prices of natural gas and NGLs that were used to calculate the present value of future net revenues from our estimated proved oil and natural gas reserves throughout 2012. The Italian write-down resulted from our conclusion that our Italian natural gas reserves could no longer be classified as proved reserves, due to an Italian regional regulatory body's 2012 denial of approval of an envir