FOREST OIL CORP
Form 10-K
March 15, 2004

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ý **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2003

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**
1600 Broadway **Suite 2200** **Denver, Colorado** (Address of principal executive offices)	**80202** (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:
Title of Each Class
Warrants to purchase Common Stock, expiring February 15, 2005
Warrants to purchase Common Stock, expiring March 20, 2010

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is an accelerated filer. Yes ý No o

The aggregate market value of the voting stock held by non-affiliates as of June 30, 2003, the last business day of the registrant's most recently completed second fiscal quarter, was $1,023,721,464 (based on the closing price of such stock on the New York Stock Exchange Composite Tape).

There were 53,733,381 shares of the registrant's Common Stock, Par Value $.10 Per Share outstanding as of February 27, 2004.

Document incorporated by reference: Portions of the registrant's definitive proxy statement for the Forest Oil Corporation annual meeting of shareholders to be held on May 13, 2004, are incorporated by reference into Part III of this Form 10-K.

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PART I

Throughout this Form 10-K, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. See Item 1, Business Forward-Looking Statements, below. Historical statements made herein are accurate only as of the date of filing this Form 10-K with the Securities and Exchange Commission and may be relied upon only as of that date.

In this report, quantities of oil or natural gas liquids are expressed in barrels (BBLS), thousands of barrels (MBBLS) or millions of barrels (MMBBLS). One barrel equals 42 U.S. gallons. Quantities of natural gas are expressed in thousands of cubic feet (MCF), millions of cubic feet (MMCF) or billions of cubic feet (BCF). Equivalent units are expressed in thousand cubic feet of gas equivalents (MCFE), million cubic feet of gas equivalents (MMCFE), or billion cubic feet of gas equivalents (BCFE). Liquids are converted to gas at one barrel of oil equaling six MCF of gas. The term liquids is used to describe oil, condensate and natural gas liquids (NGL). With respect to information relating to Forest's working interest in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by Forest's working interest therein.

Item 1. Business

The Company

Throughout this Form 10-K we use the terms "Forest", "Company", "we", "our" and "us" to refer to Forest Oil Corporation and its subsidiaries. Forest is an independent oil and gas company engaged in the acquisition, exploration, development and production of natural gas and liquids in North America and selected international locations. 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. On December 31, 2003, we had 458 employees. Our common stock, par value $.10 per share, is traded on the New York Stock Exchange under the symbol "FST."

We operate from offices located in Denver, Colorado; Lafayette and Metairie, Louisiana; Anchorage, Alaska; and Calgary, Alberta, Canada. Our corporate headquarters is located at 1600 Broadway, Denver, Colorado, 80202, telephone 303.812.1400. Information about Forest, including the periodic and current reports that it files with the Securities and Exchange Commission, and all amendments thereto, are accessible, free of charge, on Forest's website, *www.forestoil.com*, as soon as reasonably practicable after filing with the SEC.

In 2003, we operated in five business units: the Gulf Coast, Western United States, Alaska, Canada and International. We conduct exploration and development activities in each of our North American core areas and in selected international locations. Our proved reserves and producing properties are all located in North America. At December 31, 2003, approximately 88% of our proved oil and gas reserves were in the United States and approximately 12% in Canada.

For information with respect to our reserves, see Item 2, Properties, of this Form 10-K. For financial information relating to our geographic and operational segments, see Note 12 of Notes to Consolidated Financial Statements of this Form 10-K.

Exploration and Production Activities

At December 31, 2003, we held interests in approximately 1,989 net oil and gas wells in the United States and Canada. During 2003, we drilled a total of 129 gross wells, 25 of which were injection wells. Of the remaining 104 wells, 23 were exploration and 81 were development. Our 2003 drilling program achieved an 82% success rate. During 2003, we sold 149 BCFE or an average of 409 MMCFE per day. Approximately 87% of our total production in 2003 was in the United States and approximately 13% in

Canada. Our operations conducted through our U.S. and Canadian business units are summarized below.

2003 Exploration and Production Activities in North America

Business Unit	Primary Areas	% Total Production	2003 Sales Volumes/Average Daily Volume	% Total Estimated Reserves At 12/31/03	Number of Wells Drilled in 2003/ Productive No. of Wells
Gulf Coast(1)	South Texas Louisiana Gulf Coast Offshore Gulf of Mexico	58%	87 BCFE/ 240 MMCFE	48%	25/19
Western United States	Oklahoma Utah Wyoming West Texas SE New Mexico	15%	22 BCFE/ 61 MMCFE	30%	33/26
Alaska(2)	Primarily Cook Inlet Area	14%	21 BCFE/ 57 MMCFE	10%	3/2
Canada	Alberta Plains Region and Foothills British Columbia NW Territories	13%	19 BCFE/ 51 MMCFE	12%	39/37
		100%	149/409	100%	100/84

(1) Our Gulf Coast business unit was formed in the first quarter of 2003 by combining our Gulf of Mexico Offshore Region and our Gulf Coast Onshore Region to achieve greater efficiencies.

(2) During the fourth quarter of 2003, we recorded significant downward revisions of our estimated proved reserves, primarily in the Redoubt Shoal Field in the Cook Inlet, Alaska. See Item 2, Properties Reserves, of this Form 10-K.

International Business Unit. Forest also evaluates oil and gas opportunities in countries outside North America. We currently hold concessions in South Africa, Gabon, Switzerland, Germany, Albania, Italy and Romania, as well as overriding royalty interests in certain other areas. Although we have had some successful wells in South Africa, to date Forest has not recorded any proved reserves related to its international concessions. The book value of these international interests at December 31, 2003 represents approximately 1% of our total assets.

During 2003, we entered into participation agreements in connection with our exploration activities in South Africa and Germany. Pursuant to these agreements, Forest receives partial cost reimbursements and is carried for drilling costs in exchange for a reduced interest in the concessions.

During 2003, the International business unit drilled three wells in South Africa, of which one was tested, and one well in Gabon which was not productive.

Sales and Markets

Oil and Gas Operations. Forest's U.S. production of natural gas is generally sold at the wellhead in the areas where it is produced or at nearby "pooling points". Our U.S. natural gas production is

typically sold on a month to month basis in the spot market using published indices. The credit-worthiness of various purchasers is an important consideration in choosing purchasers at a given delivery point. We believe that the loss of one or more of our current natural gas spot purchasers would not have a material adverse effect on Forest's business in the United States because any individual spot purchaser could be readily replaced by another spot purchaser who would pay approximately the same sales price. Sales to BP Energy Company and Occidental Petroleum Corporation, purchasers of natural gas in the Gulf Coast, represented approximately 10% each of our total revenue in 2003.

Natural gas production in Canada has been sold by Canadian Forest Oil Ltd. ("Canadian Forest") either through a netback pool (the "Canadian Netback Pool") administered by Producers Marketing, Ltd. (ProMark) on behalf of Canadian Forest, or through Canadian Forest's direct sales contracts or under spot contracts. In 2003, Canadian Forest sold approximately 71% of its natural gas production through the Canadian Netback Pool. As described below, on March 1, 2004, the assets of ProMark were sold to a third party.

Our U.S. production of oil and natural gas liquids is typically sold under short-term contracts at prices based upon posted field prices. Canadian oil and natural gas liquids are typically sold under short-term contracts at prices based upon posted prices at Alberta pipeline and processing hubs, netted back to the field. Except in Alaska, our liquids production is generally sold at the wellhead. Our Alaskan oil production, which represented approximately 14% of our total 2003 production, is currently being sold at the terminal to one local refiner, Tesoro Alaska Petroleum Company and its affiliate. The oil is transported to a terminal by a pipeline company that is 40% owned by Forest. The primary term of our contract with this refiner expires on December 31, 2004, but will be renewed automatically from year to year thereafter unless terminated by either party upon written notice 60 days prior to expiration. Sales to this purchaser represented 15% of our total revenue in 2003.

We enter into energy swaps and collars to hedge the price of a portion of our spot market volumes against price fluctuations.

Canadian Netback Pool Sales. The Canadian Netback Pool, which was formerly administered by ProMark, matches major end users with providers of gas supply through firm transportation arrangements, and uses a netback pricing mechanism to establish the average, or "blended," wellhead price paid to producers. Under this netback arrangement, producers receive the blended well head price less related transportation and other direct costs. The administrator charges a marketing fee to the pool participant producers for marketing and administering the gas supply pool.

The Canadian Netback Pool gas sales in 2003 averaged 69 MMCF per day, of which Canadian Forest supplied approximately 29 MMCF per day or 42%. Approximately 22% of the volumes sold in the Canadian Netback Pool in 2003 were sold at fixed prices. The remainder of the volumes sold were priced in a variety of ways, including prices based on published indices. The weighted average price realized by Canadian Forest for volumes sold through the Canadian Netback Pool in 2003 was $4.51 CDN per MCF, compared to an average price of $5.31 CDN per MCF for volumes sold through other channels.

On March 1, 2004, we sold the gas marketing business of ProMark to Cinergy Canada, Inc. (Cinergy). Immediately prior to the closing, ProMark was amalgamated with Canadian Forest. Following the closing, all employees of ProMark became employees of Cinergy. Under the terms of a contract administration agreement, Cinergy will administer the Canadian Netback Pool. In addition, the parties entered into a separate agreement under which Cinergy will purchase all of Canadian Forest's natural gas that is not otherwise subject to existing contracts for a period of five years. Canadian Forest's obligation to deliver gas to the pool is not expected to change as a result of the sale. For further information concerning the ProMark sale, see Note 3 of Notes to Consolidated Financial Statements of this Form 10-K.

Competition

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Forest's competitive position depends on our geological, geophysical and engineering expertise, our acreage position and property base, our financial resources, our ability to develop properties and our ability to select, acquire and develop proved reserves. We compete with a substantial number of other companies including many companies with larger technical staffs and greater financial and operational resources. Some of these companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations, generate electricity and market refined products. We also compete with major and independent oil and gas companies in the marketing and sale of oil and gas to transporters, distributors and end users. The oil and natural gas industry competes with other industries supplying energy and fuel to industrial, commercial and individual consumers. Forest competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. Finally, companies not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies provide competition for Forest.

Forest's business is affected not only by such competition, but also by general economic developments, governmental regulations and other factors that affect our ability to market our oil and natural gas production. The prices of oil and natural gas realized by Forest are highly volatile. The price of oil is generally dependent on world supply and demand, while the price we receive for our natural gas is tied to a variety of factors such as the price of competitive fuels, the spot price at the Henry Hub, and local competition for pipeline capacity in the specific markets in which such gas is produced. Declines in crude oil prices or natural gas prices adversely impact Forest's activities. Our financial position and resources may also adversely affect our competitive position. Lack of available funds or financing alternatives can prevent us from executing our operating strategy and from deriving the expected benefits therefrom. For further information concerning Forest's financial position, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Form 10-K.

Regulation

Our oil and gas operations are subject to various U.S. federal, state and local laws and regulations and foreign laws and regulations.

United States. Various aspects of our oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the Federal government for operations on Federal leases. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions requiring permits for the drilling of wells and maintaining bonding requirements in order to drill or operate wells and provisions relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the number of wells which may be drilled in an area and the unitization or pooling of crude oil and natural gas properties. In this regard, some states can order the pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

The Federal Energy Regulatory Commission (FERC) regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978 (NGPA). In the past, the Federal government has regulated the prices at which oil and gas could be sold. The Natural Gas Wellhead Decontrol Act of 1989 (the Decontrol Act) removed all NGA and NGPA price and nonprice controls affecting producers' wellhead sales of natural gas effective January 1, 1993. While sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, Congress could enact price controls in the future.

Commencing in 1992, the FERC issued Order No. 636 and subsequent orders (collectively, Order No. 636), which require interstate pipelines to provide transportation services separate from the pipelines' sales of gas. Also, Order No. 636 requires pipelines to provide open-access transportation on a basis that is equal for all gas supplies. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations. Commencing in February 2000, the FERC issued Order No. 637 and subsequent orders (collectively, Order No. 637), which imposed a number of reforms intended to further enhance competition in natural gas markets. Most major aspects of Order No. 637 were upheld in judicial review, though certain issues were remanded to FERC, have been considered on remand, and are pending rehearing at FERC.

While any additional FERC action on these matters would affect Forest only indirectly, these changes are intended to further enhance competition in natural gas markets. We cannot predict whether and to what extent the FERC's regulations will survive rehearing and further judicial review and, if so, whether the FERC's actions will achieve the goal of increasing competition in natural gas markets in which our natural gas is sold. However, we do not believe that we will be affected materially differently than other natural gas producers and markets with which and in which we compete.

The Outer Continental Shelf Lands Act (OCSLA) requires that all pipelines operating on or across the Outer Continental Shelf (the OCS) provide open-access, non-discriminatory service. Commencing in April 2000, FERC issued Order No. 639 and subsequent orders (collectively, Order No. 639), which imposed certain reporting requirements applicable to "gas service providers" operating on the OCS concerning their prices and other terms and conditions of service. The purpose of Order No. 639 is to provide regulators and other interested parties with sufficient information to detect and to remedy discriminatory conduct by such service providers. FERC has stated that these reporting rules apply to OCS gatherers and has clarified that they may also apply to other OCS service providers including platform operators performing dehydration, compression, processing and related services for third parties. The U.S. District Court overturned the FERC's reporting rules as exceeding its authority under OCSLA. The FERC has recently appealed this decision, which was affirmed on appeal through petitions to the U.S. Supreme Court and are pending. We cannot predict whether and to what extent these regulations might be reinstated, and what effect, if any, they may have on our financial condition or operations. The rules, if reinstated, may increase the frequency of claims of discriminatory service, may decrease competition among OCS service providers and may lessen the willingness of OCS gathering companies to provide service on a discounted basis.

Certain operations that we conduct are on federal oil and gas leases, which are administered by the Bureau of Land Management (BLM) and the Minerals Management Service (MMS). These leases contain relatively standardized terms and require compliance with detailed BLM and MMS regulations and orders pursuant to the OCSLA (which are subject to change by the MMS). Many onshore leases contain stipulations limiting activities that may be conducted on the lease. The stipulations are unique to particular geographic areas and may limit the times during which activities on the lease may be conducted, the manner in which certain activities may be conducted or, in some cases, may ban any surface activity. For offshore operations, lessees must obtain MMS approval for exploration,

development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the Environmental Protection Agency), lessees must obtain a permit from the BLM or the MMS, as applicable, prior to the commencement of drilling. Lessees must also comply with detailed BLM or MMS regulations, as applicable, governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of OCS wells, calculation of royalty payments and the valuation of production for this purpose and removal of facilities. To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met, unless the MMS exempts the lessee from such obligations. The cost of such bonds or other surety can be substantial and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. Under certain circumstances, the BLM or MMS, as applicable, may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

In March 2000, the MMS issued a final rule modifying the valuation procedures for the calculation of royalties owed for crude oil sales. When oil production sales are not in arms-length transactions, the new royalty calculation will base the valuation of oil production on spot market prices instead of the posted prices that were previously utilized. We do not believe that this rule will have a material adverse effect on our operations.

Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by Congress, states, the FERC and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. We can give no assurance that the regulatory approach currently pursued by the FERC will continue indefinitely. We do not anticipate, however, that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon our capital expenditures, earnings or competitive position. No material portion of Forest's business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the Federal government.

Canada. The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size. We are unable to predict what additional legislation or amendments may be created.

Oil and natural gas exported from Canada is subject to regulation by the National Energy Board (NEB), an independent federal regulatory agency and the government of Canada. Exporters are free to negotiate with purchasers, provided that the export contracts must meet certain criteria prescribed by the NEB. Natural gas exports for a term of less than two years or for a term two to 20 years (in quantities of more than 30,000 cubic meters per day), must be made pursuant to a NEB order. Oil exports may be made pursuant to export contracts with terms not exceeding one year, in the case of light crude, and not exceeding two years, in the case of heavy crude, provided that an order approving any export has been obtained from the NEB. Any natural gas or oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the government of Canada. The provinces in which our operations are located, mainly Alberta and British Columbia, also regulate the volume of natural gas which may be removed for consumption elsewhere.

In addition, each province has regulations that govern land tenure, royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from private lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by government regulation and are

generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

In Alberta, certain producers of oil or natural gas are entitled to a credit against the royalties to the Crown by virtue of the ARTC (Alberta Royalty Tax Credit) program. The credit is determined by applying a specified rate (25-75%) to a maximum of $2 million CDN of Alberta Crown royalties payable for each producer. Canadian Forest is eligible for ARTC credits only on eligible properties acquired and wells drilled after the change of control that occurred when Canadian Forest was acquired by Forest. Production from properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible.

In British Columbia, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the quantity of oil produced and the value of the oil. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on the greater of the amount obtained by the producer and a prescribed minimum price. The minimum royalty for natural gas produced in association with oil is 8% and for other natural gas is 15%.

The federal government has jurisdiction over the exploration and development of oil and gas resources in the Northwest Territories of Canada. The federal regulatory regime reflects the extended timelines and increased capital expenditures inherent in working in the northern environment, providing for work commitments and work deposits coupled with the suspension and/or reimbursement of rentals and royalties at earlier developmental stages. This regime is subject to change as development in the Northwest Territories evolves toward a more conventional model. It is also possible that jurisdiction over the oil and gas resources in these territories could be transferred to the territorial governments. We are unable to predict whether any evolution or transfer of jurisdiction to the territorial governments would affect our activities in the Northwest Territories.

Our right to produce oil and gas from the Northwest Territories is subject to conversion of certain instruments (i.e., exploration licenses or significant discovery licenses) into production licenses. The right to such conversion is subject to an application process and regulatory approval. In addition, the right to produce may be dependent on the negotiation of a pooling agreement or the imposition of a forced pooling order. Until the finalization of such agreement or order, it is not possible to finally determine our production in such lands.

Environmental Matters. Extensive U.S. federal, state and local laws, as well as laws of foreign countries, govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (commonly called the EPA), issue regulations to implement and enforce such laws. Environmental laws and regulations are often difficult and costly to comply with and substantial administrative, civil and even criminal penalties can be imposed for failure to comply. These laws and regulations may, in certain circumstances, impose "strict liability" for environmental contamination, rendering an owner or lessee liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of the owner or lessee. This regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. Changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations or earnings, as well as the oil and gas exploration and production industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations 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.

The Oil Pollution Act of 1990 (OPA) and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. A "responsible party" includes the owner or operator of a pipeline, vessel or onshore facility, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages from oil spills. OPA also requires operators of offshore OCS facilities to demonstrate to the MMS that they possess at least $35 million in financial resources that are available to pay for costs that may be incurred in responding to an oil spill. This financial responsibility amount can increase up to a maximum of $150 million if the MMS determines that a greater amount is justified based on specific risks posed by the operations or if the worst case oil-spill discharge volume possible at a facility exceeds applicable threshold volumes established by the MMS. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages, while the liability limits for onshore facilities are $350 million. Few defenses exist to the liability imposed by OPA.

The U.S. Federal Water Pollution Control Act (commonly called the Clean Water Act) imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes in "waters of the United States," a broadly-defined term that includes all navigable waters. Many state discharge regulations and the federal National Pollutant Discharge Elimination System generally prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into coastal waters. Although the costs to comply with these zero discharge mandates under federal or state law may be significant, the entire industry is expected to experience similar costs and we believe that these costs will not have a material adverse impact on our financial condition and operations.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended (commonly called CERCLA but also known as "Superfund") and comparable state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current owner and operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances that have been released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. In the ordinary course of Forest's operations, substances may be generated that fall within the definition of "hazardous substances." Although we have utilized operating and disposal practices that were standard in the industry at the time, wastes associated with oil and gas exploration and production operations may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. Moreover, we may own or operate properties that in the past were operated by third parties whose operations were not under our control. Those properties and any wastes that may have been disposed or released on them may be subject to CERCLA, and analogous state laws, and we potentially could be required to remediate such properties.

In Canada, the oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation that provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized with oil and gas industry operations. In

addition, wells and facility sites must be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of fines and penalties, the revocation of licenses and authorizations or civil liability for pollution damage.

Although we maintain insurance against some, but not all, of the risks described above, including insuring the costs of clean-up operations, public liability and physical damage, there is no assurance that such insurance will be adequate to fully cover all such costs or that such insurance will continue to be available in the future or that such insurance will be available at premium levels that justify its purchase. The occurrence of a significant environmental-related event not fully insured or indemnified against could have a material adverse effect on our financial condition and operations.

We have established guidelines to be followed to comply with U.S. and Canadian environmental laws and regulations. We employ an environmental 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 clean-up 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, any oil and gas activities conducted by us outside of North America are potentially subject to similar foreign governmental controls and restrictions pertaining to the environment. To date we believe that compliance with existing requirements of such governmental bodies has not had a material effect on our operations.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures as a result of increasingly stringent laws relating to the protection of the environment.

For further information regarding certain environmental matters, see Item 3, Legal Proceedings, in this Form 10-K.

Available Information

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to reports filed pursuant to Sections 13(a) and 15(d) of the Securities Exchange Act of 1934 are available on our website, *www.forestoil.com*, as soon as reasonably practicable after such reports are electronically filed with the Securities and Exchange Commission. In addition our corporate governance guidelines, code of ethics, and charters for the Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee are also available on our website. Copies of the foregoing information is available to shareholders upon written request addressed to the attention of the Secretary of Forest at 1600 Broadway Street, Suite 2200, Denver, Colorado 80202.

Forward-Looking Statements

The information in this Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts 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 are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K, in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations Risk Factors.

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

- estimates of our oil and gas reserves;
- estimates of our future natural gas and liquids production, including estimates of any increases in oil and gas production;
- planned capital expenditures and availability of capital resources to fund capital expenditures;
- our outlook on oil and gas prices;
- the impact of political and regulatory developments;

our future financial condition or results of operations and our future revenues and expenses; and

our business strategy and other plans and objectives for future operations.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures and the other risks described in Part II, Item 7, under the caption " Risk Factors." The financial results of our foreign operations are also subject to currency exchange rate risks.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements express or implied, included in this 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 Forest or persons acting on its behalf may issue. Forest does not undertake to update any forward-looking statements to reflect events or circumstances after the date of filing this Form 10-K with the Securities and Exchange Commission, except as required by law.

Item 2. Properties

Forest's principal proved reserves and producing properties are located in the United States in Louisiana, New Mexico, Oklahoma, Texas, Utah, Wyoming, Alaska and the Gulf of Mexico, and in Canada in Alberta. In addition, we have acreage in various locations outside North America.

Reserves

Information regarding Forest's proved and proved developed oil and gas reserves and the standardized measure of discounted future net cash flows and changes therein is included in Note 13 of Notes to Consolidated Financial Statements. See also Part II, Item 7, Management's Discussion and

Analysis of Financial Condition and Results of Operations Risk Factors *Estimates of oil and gas reserves are uncertain and inherently imprecise*, for additional information regarding estimates of proved reserves.

Since January 1, 2003 we have not filed any oil or natural gas reserve estimates or included any such estimates in reports to any Federal or foreign governmental authority or agency, other than the Securities and Exchange Commission (SEC) and the Department of Energy (DOE). There were no differences between the reserve estimates included in the SEC report, the DOE report and those included herein, except for production and additions and deletions due to the difference in the "as of" dates of such reserve estimates.

Forest's estimated proved reserves were 1,296 BCFE at December 31, 2003 compared to estimated proved reserves of 1,560 BCFE at December 31, 2002. Approximately 62% of our estimated proved reserves at December 31, 2003 were natural gas and our estimated proved developed reserves represented approximately 75% of total estimated proved reserves.

Forest's year-end 2003 estimates of proved reserves were independently reviewed by two independent petroleum engineering firms. Ryder Scott Company independently reviewed our estimates of the reserves attributable to certain properties in the United States and Canada, except the properties acquired by us on December 31, 2003 in the Permian Basin and South Texas, which were independently reviewed by DeGolyer and MacNaughton.

In conducting an independent review of Forest's estimates of proved reserves each petroleum engineering firm prepared independent estimates of reserves for specific fields. The estimates prepared by each petroleum engineering firm were presented to Forest by field for oil, gas and natural gas liquids. The estimates prepared by the engineering firms were then compared to the estimates prepared by Forest in the aggregate on a gas equivalent basis. Together, these firms independently reviewed estimates relating to properties constituting approximately 88% of our reserves based on their discounted value and volumes. In the aggregate, for the properties reviewed, the estimates of proved reserve quantities prepared by the two independent petroleum engineering firms as part of their reviews were lower than Forest's estimates by approximately 8%. Upon consummation of their reviews, Ryder Scott Company and DeGolyer and MacNaughton each provided Forest with their opinions that Forest's estimates of proved reserves for the properties reviewed by them complied with the definitions and disclosure guidelines of the SEC.

2003 Reserve Revisions. During 2003 we revised downward our estimate of proved reserves by a total of approximately 473 BCFE. The downward revision of our estimates was due to information received from production results, drilling activity and other events that occurred primarily in the latter part of 2003. The revisions are not expected to have a material impact on our near-term hydrocarbon production volumes.

Approximately 62% of the total revisions was attributable to the downward revision of our estimate of proved oil reserves in the Redoubt Shoal Field in the Cook Inlet, Alaska. We reduced our estimate of proved oil reserves associated with our Redoubt Shoal Field in Alaska from our 2002 year-end estimate by approximately 49 million barrels, or approximately 85% of the estimated proved oil reserves of this field as of December 31, 2002. Of this revision, approximately 36 million barrels were classified as proved undeveloped as of December 31, 2002. Our estimate of proved oil reserves attributable to the Redoubt Shoal Field was approximately 8 million barrels as of December 31, 2003. On December 31, 2003, Forest's net daily oil production at the Redoubt Shoal Field was approximately 1,650 barrels per day from three wells. On that date one well was shut in for pump repair.

Production results in 2003 from Redoubt Shoal, which began production in December 2002, were lower than those originally estimated. In addition, data from wells drilled in 2003 in Redoubt Shoal,

when integrated with pre-existing data, reflected significantly lower oil in place than the estimates at December 31, 2002, lower overall recovery efficiencies and economic cutoffs. During the second half of 2003 Forest undertook an integrated field study of the Redoubt Shoal Field examining the production performance, field data and well data for 2003 activity. The revision was a result of the study, after applying economic cutoffs. In addition to preparing and reporting its own internal estimates of proved reserves at Redoubt Shoal, Forest also engaged Ryder Scott Company to prepare independent estimates of proved reserves at Redoubt Shoal as of the end of 2003, 2002 and 2001.

Cumulative investment in exploration, delineation and development of the Redoubt Shoal Field by Forest and its predecessor, Forcenergy Inc (Forcenergy), through December 31, 2003 was approximately $310 million. As of December 31, 2003, we estimated total future development capital expenditures, excluding abandonment, for the Redoubt Shoal Field to be approximately $53 million. This amount includes the remaining cost of implementing the water injection project described below.

Forest's future development plans for the Redoubt Shoal Field currently include the implementation of a water injection project for the purpose of maintaining the average Hemlock reservoir pressure, conserving the natural energy of the reservoir and assisting oil recovery.

Implementation of the water injection project is currently planned to begin within the next two years. Our current plans call for the drilling of two oil wells and one water injection well and the conversion of three wells from production to water injection, over several years.

We also had downward revisions in our estimated proved reserves for other properties in the fourth quarter of 2003 totaling approximately 143 BCFE. These revisions were in addition to 36 BCFE of downward revisions to estimated proved reserves taken previously in 2003. These downward revisions are due to a variety of factors, including recent production performance and revised field development plans.

Production

The following table shows our net liquids and natural gas production for the years ended December 31, 2003, 2002 and 2001:

	Net Natural Gas and Liquids Production		
	2003	2002	2001
United States:			
Natural Gas (MMCF)	84,368	78,543	97,400
Liquids (MBBLS)	7,686	7,477	9,239
Total (MMCFE)	130,484	123,405	152,834
Canada:			
Natural Gas (MMCF)	12,609	13,525	10,994
Liquids (MBBLS)	1,015	1,180	1,361
Total (MMCFE)	18,699	20,605	19,160
Consolidated:			
Natural Gas (MMCF)	96,977	92,068	108,394
Liquids (MBBLS)	8,701	8,657	10,600
Total (MMCFE)	149,183	144,010	171,994

Average Sales Prices

The following table sets forth production volumes and average sales prices per MCF of natural gas and per barrel of liquids for the years ended December 31, 2003, 2002 and 2001:

		United States			Canada		
		2003	2002	2001	2003	2002	2001
Natural Gas:							
Sales volumes (MMCF)		84,368	78,543	97,400	12,609	13,525	10,994
Sales price received (per MCF)	$	5.27	3.18	4.33	3.09	2.05	2.56
Effects of energy swaps and collars (per MCF)(1)	$	(.52)	.14	.18			
Average sales price (per MCF)	$	4.75	3.32	4.51	3.09	2.05	2.56
Liquids:							
Oil and condensate:							
Sales volumes (MBBLS)		7,221	6,792	8,264	629	739	955
Sales price received (per BBL)	$	29.08	24.30	23.92	28.57	23.37	22.96
Effects of energy swaps and collars (per BBL)(1)	$	(4.04)	(1.90)	.62			
Average sales price (per BBL)	$	25.04	22.40	24.54	28.57	23.37	22.96
Natural gas liquids:							
Sales volumes (MBBLS)		465	685	975	386	441	406
Average sales price (per BBL)	$	18.58	11.57	15.81	20.88	13.35	17.17
Total liquids sales volumes (MBBLS)		7,686	7,477	9,239	1,015	1,180	1,361
Average sales price (per BBL)	$	24.65	21.40	23.62	25.65	19.63	21.23
Total Sales Volumes:							
Sales volumes (MMCFE)		130,484	123,405	152,834	18,699	20,605	19,160
Average sales price (per MCFE)(1)	$	4.52	3.41	4.30	3.47	2.47	2.97
Oil and gas production expense (per MCFE)	$	1.07	1.17	1.12	.77	.67	.82

(1) Commodity swaps and collars were transacted to hedge the price of spot market volumes against price fluctuations. Hedged natural gas volumes were 49,990 MMCF, 36,050 MMCF, and 42,870 MMCF for the years ended December 31, 2003, 2002 and 2001, respectively. Hedged oil and condensate volumes were 4,597,500 barrels, 3,921,500 barrels, and 3,742,500 barrels for 2003, 2002 and 2001, respectively. These arrangements have been designated as cash flow hedges for accounting purposes and, as a result, the effective portion of the net gains and losses were accounted for as increases and decreases of oil and gas sales. The aggregate net gains (losses) related to our cash flow hedges were $(72,863,000), ($1,742,000), and $22,781,000 for the years ended December 31, 2003, 2002 and 2001, respectively. Those arrangements that are not designated as cash flow hedges for accounting purposes are recorded as non-operating income or expense. Average sales prices have been adjusted to reflect effects of energy swaps and collars.

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Productive Wells

The following summarizes our total gross and net productive wells at December 31, 2003:

	Productive Wells(1)	
	United States	**Canada**
Gross(2)		
Gas	1,011	231
Oil	2,716	346
Totals(3)	3,727	577
Net(4)		
Gas	390	116
Oil	1,267	216
Totals	1,657	332

(1) Productive wells are producing wells and wells capable of production, including injection wells, salt water disposal wells, service wells and wells that are shut-in.

(2) The number of gross wells is the total number of wells in which a working interest is owned.

(3) Includes 6 dual completions in the United States and 8 dual completions in Canada. Dual completions are counted as one well. If either completion is an oil completion, the well is classified as an oil well.

(4) The number of net wells is the sum of the fractional working interests owned in gross wells, expressed as whole numbers.

Developed and Undeveloped Acreage

Forest held acreage as set forth below at December 31, 2003 and 2002. A majority of the developed acreage is subject to mortgage liens securing our bank indebtedness. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 4 of Notes to Consolidated Financial Statements in this Form 10-K.

	Developed Acreage(1)		Undeveloped Acreage(2)	
	Gross(3)	Net(4)	Gross(3)	Net(4)
United States:				
Gulf Coast	1,058,316	482,651	416,177	306,648
Western	312,958	98,636	251,999	114,926
Alaska	305,030	37,379	1,438,220	1,208,798
	1,676,304	618,666	2,106,396	1,630,372
Canada	209,189	102,887	1,419,937	794,722
International:				
South Africa			8,986,446	5,167,647
Gabon			2,409,276	2,409,276
Switzerland			1,850,000	925,000
Germany			1,050,807	315,241
Albania			855,123	320,670
Italy			940,926	743,230
Romania			1,073,693	1,073,693
			17,166,271	10,954,757
Total acreage at December 31, 2003	1,885,493	721,553	20,692,604	13,379,851
United States	1,297,337	428,311	1,876,857	1,466,570
Canada	210,475	106,657	1,238,150	534,380
International			18,637,048	12,067,753
Total acreage at December 31, 2002	1,507,812	534,968	21,752,055	14,068,703

(1) Developed acres are those acres which are spaced or assigned to productive wells.

(2) Undeveloped acres are those acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. It should not be confused with undrilled acreage held by production under the terms of a lease.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres, expressed as whole numbers.

Approximately 5% and 13% of our North American net undeveloped acreage at December 31, 2003 is held under leases that have terms that will expire in 2004 and 2005, respectively, if not extended by exploration or production activities.

In addition, 36% and 13% of our International net undeveloped acreage is expected to be relinquished in 2004 and 2005, respectively, as part of contractual commitments in South Africa, Gabon and Albania.

Drilling Activity

During the years ended December 31, 2003, 2002 and 2001, Forest drilled gross and net exploratory and development wells as set forth below. This information does not include wells drilled under farmout agreements, royalty interests ownership or any other wells in which we do not have a working interest.

	United States			Canada			International		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
Gross Exploratory Wells:									
Dry(1)	5	5	8	1	6	3	3		2
Productive(2)	8	1	69	5	4	15	1		2
	13	6	77	6	10	18	4		4
Net Exploratory Wells:(3)									
Dry(1)	4.2	2.3	4.9	.7	3.5	1.4	1.5		1.0
Productive(2)	6.7	.7	38.3	3.1	1.9	8.9	.5		1.4
	10.9	3.0	43.2	3.8	5.4	10.3	2.0		2.4
Gross Development Wells:									
Dry(1)	9	4	2	1	2	2			
Productive(2)	39	43	8	32	4				
	48	47	10	33	6	2			
Net Development Wells:(3)									
Dry(1)	5.6	2.3	1.3	.3	.7				
Productive(2)	23.0	23.5	5.4	12.7	3.0	.7			
	28.6	25.8	6.7	13.0	3.7	.7			

(1) A dry well (hole) 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.

(2) Productive wells are producing wells and wells capable of production, including wells that are shut-in.

(3) The number of net wells is the sum of the fractional working interests owned in gross wells, expressed as whole numbers and fractions thereof.

At December 31, 2003 Forest had 5 exploratory wells (2.3 net) and 8 development wells (3.1 net) that were in the process of being drilled.

Delivery Commitments

A significant portion of Canadian Forest's natural gas production in 2003 was sold through the Canadian Netback Pool which was administered by ProMark on behalf of Canadian Forest. The gas marketing business of ProMark was sold to Cinergy on March 1, 2004. Canadian Forest will continue to sell a significant portion of its natural gas production into the Canadian Netback Pool, which Cinergy will administer pursuant to a contract administration agreement. Also, under our agreement with Cinergy, Canadian Forest will sell and Cinergy will purchase for a period of five years all of Canadian Forest's natural gas that is not otherwise subject to the Canadian Netback Pool or existing contracts. Cinergy will pay for the natural gas based on published indices less applicable transportation costs. At December 31, 2003, the natural gas quantities and weighted average contract prices related to the fixed price contracts of the Canadian Netback Pool were as follows:

	Canadian Netback Pool Sales Commitment	
	BCF	Weighted Average Contract Price per MCF
2004	5.5	$2.66 CDN
2005	5.5	$2.75 CDN
2006	5.5	$2.86 CDN
2007	5.5	$2.96 CDN
2008	5.5	$3.08 CDN
2009	3.0	$3.86 CDN
2010	1.7	$5.21 CDN
2011	.7	$5.50 CDN

As a producer in the Canadian Netback Pool, Canadian Forest will be paid a netback price that reflects all of the revenue from approved customers less the costs of delivery (including transportation, audit and shortfall makeup costs) and an administrator marketing fee.

In 2003 Canadian Forest supplied 42% of the Canadian Netback Pool sales quantity; the amount supplied represented 71% of Canadian Forest's 2003 natural gas production. In order to satisfy its supply obligations to the Canadian Netback Pool, Canadian Forest may be required to cover its obligations in the market.

The administrator of the Canadian Netback Pool, now Cinergy, is required to acquire gas in the event of a shortfall between the gas supply and market obligations. A shortfall could occur if a gas producer fails to deliver its contractual share of the supply obligations of the Canadian Netback Pool. The cost of purchasing gas to cover any shortfall is a cost of the Canadian Netback Pool. The prices paid for shortfall gas would typically be spot market prices and may differ from the prices received from customers of the Canadian Netback Pool. Higher spot prices would reduce the average price paid to the gas producers in the Canadian Netback Pool, including Canadian Forest.

In addition to its commitments to the Canadian Netback Pool, Canadian Forest is committed to sell natural gas at the following quantities and weighted average prices:

	Natural Gas	
	BCF	Sales Price per MCF
2004	.5	$3.96 CDN
2005	.5	$4.11 CDN
2006	.4	$4.27 CDN

There were no long-term delivery commitments in the United States as of December 31, 2003.

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Item 3. Legal Proceedings

Forest, in the ordinary course of business, is a party to various lawsuits, claims and proceedings, including those identified below. While we believe that the amount of any potential loss would not be material to our consolidated financial position, the ultimate outcome of these matters is inherently difficult to predict with any certainty. In the event of an unfavorable outcome, the potential loss could have an adverse effect on our results of operations and cash flow in the reporting periods in which any such actions are resolved.

Alaska Proceeding. In May, 2002, Cook Inlet Keeper, a non-governmental third party, filed a challenge in the Superior Court in Anchorage, Alaska (the trial court) to the regulatory review and approval process for Forest's development and production phase of our Redoubt Shoal project (the Production Project). On February 2, 2004, the trial court ruled that certain legislation which became law in 2003 mooted Cook Inlet Keeper's challenge and, therefore, affirmed the State's approval of the Production Project. While we will continue our vigorous opposition to Cook Inlet Keeper's challenge, the outcome of the litigation is inherently difficult to predict with any certainty. However, the Company does not believe that this legal matter could have a material effect on the results of future periods in the event of an unfavorable outcome.

Environmental Matters. The Company is involved in a number of governmental proceedings in the ordinary course of business, including the environmental matters described below. Forest believes that the potential penalty for each of the proceedings described below could involve penalties in excess of $100,000. Forest believes, however, that mitigating circumstances will result in total monetary penalties of $150,000 to $300,000 for all three proceedings combined.

Forest owns and operates a platform located in the Cook Inlet, Alaska. Discharges from the platform have on occasion exceeded the limits allowed by the EPA discharge permit. Forest recently received permission from the State of Alaska to inject the effluent into a disposal well rather than discharge it into the Cook Inlet.

Forest also owns a non-operating working interest in the King Salmon platform in the Cook Inlet in Alaska. In September 2002, while injecting oil based drilling mud and cuttings into the annulus of the well, the operator observed an oil sheen on the water near the platform and ceased further injections. The U.S. Coast Guard initiated an enforcement action based on the apparent discharges into the Cook Inlet. In addition, the State of Alaska Department of Environmental Conservation has indicated that it may also initiate an enforcement action.

In addition, Forest received a Findings of Violation for alleged violations of the Clean Water Act involving discharges from 1999 to 2002 from facilities in the Gulf of Mexico that were previously operated by Forcenergy. All alleged violations have been remedied.

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

No matter was submitted to a vote of our shareholders during the fourth quarter of the fiscal year ended December 31, 2003.

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Item 4A. Executive Officers of Forest

The following persons were serving as executive officers of Forest as of March 1, 2004.

Name	Age	Years with Forest	Office(1)
H. Craig Clark	47	3	President and Chief Executive Officer, and a director since July 31, 2003. Mr. Clark joined Forest in September 2001, and served as President and Chief Operating Officer through July 2003. Mr. Clark was previously employed by Apache

Name	Age	Years with Forest	Office(1)
			Corporation in Houston, Texas, an independent energy company, from 1989 to 2001. He served in various management positions during this period, including Executive Vice President U.S. Operations and Chairman and Chief Executive Officer of Pro Energy, an affiliate of Apache.
David H. Keyte	47	16	Executive Vice President and Chief Financial Officer since November 1997. Mr. Keyte served as our Vice President and Chief Financial Officer from December 1995 to November 1997 and our Vice President and Chief Accounting Officer from December 1993 to December 1995.
Forest D. Dorn	49	26	Senior Vice President Corporate Services since December 2000. Mr. Dorn served as Senior Vice President Gulf Coast Region from November 1997 to December 2000, Vice President Gulf Coast Region from August 1996 to October 1997 and Vice President and General Business Manager from December 1993 to August 1996.
Leonard C. Gurule	47	1	Senior Vice President Alaska since joining the Company on September 22, 2003. Between 2000 and September 2003, Mr. Gurule served on the boards of several local community and non-profit organizations and managed his own investment portfolio. From 1987 to 2000, he served in various capacities at Atlantic Richfield Co., including Chairman of the Board and Chief Executive Officer of Virginia Indonesia, a company owned by ARCO, and manager of ARCO's Prudhoe Bay operations and construction activities, engineering support to ARCO's Alaskan exploration activities and petroleum engineering support to ARCO's Kuparuk field.

Name	Age	Years with Forest	Office(1)
James W. Knell	53	16	Senior Vice President Gulf Coast Region since December 2000. Mr. Knell served as Vice President Gulf Coast Offshore from May 1999 to December 2000, Gulf Coast Offshore Business Unit Manager from March 1998 to May 1999, Gulf Coast Region Business Unit Manager from November 1997 to March 1998 and Corporate Drilling and Production Manager from December 1991 to November 1997.
John F. McIntyre III	48	5	Senior Vice President since May 2003. Prior to that from September 1998 to April 2003, he served as Senior Vice President of Forest Oil International Corporation, one of our wholly owned subsidiaries. Prior to joining Forest in September 1998, he served as Joint Venture Manager for YPF, a oil and gas company in Argentina.
Newton W. Wilson III	53	3	Senior Vice President General Counsel and Secretary since December 2000. Mr. Wilson served as a consultant to Mariner Energy LLC from 1999 to December 2000 and a consultant to Sterling City Capital from 1998 to 1999. He served in various capacities at Union Texas Petroleum Holdings, Inc. from 1993-1998, and was President and Chief Operations Officer of Union Texas Americas Ltd. from 1996 to 1998.

Matthew A. Wurtzbacher	41	5	Senior Vice President Corporate Planning and Development since May 2003. From December 2000 to May 2003, he served as our Vice President Corporate Planning and Development and from June 1998 to December 2000, he served as Manager Operational Planning and Corporate Engineering.
Joan C. Sonnen	50	14	Vice President Controller and Chief Accounting Officer since December 2000. Ms. Sonnen served as our Vice President Controller and Corporate Secretary from May 1999 to December 2000 and has served as our Controller since December 1993.

R. Scot Woodall	42	4	Vice President Western United States business unit since March 2004. Mr. Woodall joined Forest in October 2000 and served as Production and Engineering Manager for the Western Region. From 1992 to September 2000 he served as Operations and Engineering Manager Rocky Mountain Division, at Santa Fe Synder Corporation.

(1) The term of office of each officer is one year from the date of his or her election immediately following the last annual meeting of shareholders and until the officer's respective successor has been elected and qualified or until his or her earlier death, resignation or removal from office whichever occurs first.

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

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 27, 2004, there were 53,733,381 outstanding shares of our Common Stock held by 799 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 of the Common Stock on the New York Stock Exchange composite tape during each fiscal quarterly period of 2002 and 2003. There were no dividends declared on the Common Stock in 2002 or 2003. On February 27, 2004, the closing price of Forest Common Stock was $25.95.

		High	Low
2002:	First Quarter	$ 29.95	$ 23.50
	Second Quarter	32.44	26.95
	Third Quarter	28.75	20.69
	Fourth Quarter	29.06	22.97
2003:	First Quarter	28.75	19.65
	Second Quarter	27.02	20.52
	Third Quarter	25.40	19.80

	High	Low
Fourth Quarter	29.56	23.21

Warrants

Forest's warrants are quoted on the NASDAQ Bulletin Board. At December 31, 2003, Forest had three series of warrants outstanding.

2004 Warrants. At December 31, 2003, Forest had outstanding 236,030 warrants expiring on February 15, 2004 (the 2004 Warrants), which were held by 422 holders of record. Each 2004 Warrant entitled the holder to purchase 0.8 shares of Common Stock for $16.67, or an equivalent per share price of $20.84. From January 1, 2004 through February 15, 2004, 210,337 warrants were exercised via both cash and cashless exercise provisions pursuant to which 151,938 shares of Common Stock were issued. On February 15, 2004, the remaining 2004 Warrants expired unexercised.

2005 Warrants. At February 27, 2004, Forest had outstanding 237,394 warrants expiring on February 15, 2005 (the 2005 Warrants), which were held by 425 holders of record. Each 2005 Warrant entitles the holder to purchase 0.8 shares of Common Stock for $20.83, or an equivalent per share price of $26.04. Forest's 2005 Warrants are quoted on the NASDAQ Bulletin Board under the symbol "FTYLZ.OB." On February 27, 2004, or the last day of activity prior thereto, the closing price of the 2005 Warrants was $2.31. The table below reflects the high and low intraday sales prices of the 2005 Warrants on the NASDAQ Bulletin Board during each fiscal quarter in 2002 and 2003.

		High	Low
2002:	First Quarter	$ 8.00	$ 6.20
	Second Quarter	9.80	7.50
	Third Quarter	9.65	6.50
	Fourth Quarter	7.95	5.00
2003:	First Quarter	7.00	3.05
	Second Quarter	3.90	2.51
	Third Quarter	2.85	1.25
	Fourth Quarter	3.50	1.50

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Subscription Warrants. At February 27, 2004, Forest also had outstanding 1,752,355 subscription warrants (the Subscription Warrants), which were held by 10 holders of record. Each Subscription Warrant entitles the holder to purchase 0.8 shares of Common Stock for $10.00, or an equivalent per share price of $12.50. The Subscription Warrants expire on March 20, 2010 or earlier upon notice of expiration by Forest if, after March 20, 2004, the market price of the Common Stock has exceeded 300% of the exercise price, or $37.50 per share, for a period of 30 consecutive trading days. Forest's Subscription Warrants are quoted on the NASDAQ Bulletin Board under the symbol "FTYLL.OB". On February 27, 2004, or the last day of activity prior thereto, the closing price of the Subscription Warrants was $13.00. The table below reflects the high and low intraday sales prices of the Subscription Warrants on the NASDAQ Bulletin Board during each fiscal quarter in 2002 and 2003.

		High	Low
2002:	First Quarter	$ 15.00	$ 15.00
	Second Quarter	17.75	14.50
	Third Quarter	14.13	11.00
	Fourth Quarter	14.91	9.75
2003:	First Quarter	13.75	9.00
	Second Quarter	10.00	9.30
	Third Quarter	14.00	10.25
	Fourth Quarter	15.00	15.00

Forest's warrants were originally issued by Forcenergy in connection with its plan of reorganization under the Bankruptcy Code, and were converted into warrants to purchase Forest common stock pursuant to our merger with Forcenergy on December 7, 2000. The issuance of Forest common stock upon exercise of the warrants is exempt from registration under the Securities Act of 1933 pursuant to section 1145 of the Bankruptcy Code. During 2003, Forest issued 1,573 shares of common stock pursuant to the exercise of warrants.

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 8% Senior Notes due 2008, Forest's 8% Senior Notes due 2011 and Forest's $7^3/_4$% Senior Notes due 2014, and (iii) our credit facilities dated as of December 7, 2000 with JPMorgan Chase and JPMorgan Chase Bank, Toronto Branch. The provisions in the indentures pertaining to the 8% Senior Notes due 2008 and 2011 and the $7^3/_4$% Senior Notes due 2014, and the credit facilities limit our ability to make restricted payments, which include dividend payments.

Forest has not paid dividends on its Common Stock during the past five years and does not presently anticipate that it will do so in the foreseeable future. The future payment of 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 dividends. For further information regarding our equity securities and our ability to pay dividends on our Common Stock, see Notes 4 and 6 of Notes to Consolidated Financial Statements.

For equity compensation plan information, see Part III, Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, of this Form 10-K.

PART II

Item 6. Selected Financial and Operating 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, 2003. 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.

On December 7, 2000, Forest completed its merger with Forcenergy. The merger was accounted for as a pooling of interests for accounting and financial reporting purposes. Under this method of accounting, the recorded assets and liabilities of Forest and Forcenergy were carried forward to the combined company at their recorded amounts on the date of the merger. Income and expense amounts reported for the combined company for 2000 include amounts attributable to the operations of both Forest and Forcenergy for the entire year. Forcenergy was merged into Forest on the date of the merger and, accordingly, all amounts attributable to periods after the merger represent the operations of the combined entities. The results of operations of Forcenergy prior to December 31, 1999, the effective date of its reorganization and fresh-start reporting, are not included in the financial statements of the combined company. In conjunction with the merger with Forcenergy, Forest effected a 1-for-2 reverse stock split. Unless otherwise indicated, all share and per share amounts included herein give retroactive effect to this reverse stock split.

		Years Ended December 31,				
		2003	2002	2001	2000	1999
		(In Thousands Except Per Share Amounts, Volumes and Prices)				
FINANCIAL DATA						
Revenue:						
Oil and gas sales	$	655,193	471,740	714,852	623,624	189,895
Processing income, net		1,985	1,128	(85)	213	3,104
Total revenue	$	657,178	472,868	714,767	623,837	192,999
Net earnings from continuing operations	$	90,228	21,083	106,437	117,151	20,276
(Loss) income from discontinued operations (net of tax)		(7,731)	193	(2,694)	13,457	(1,233)
Cumulative effect of change in accounting principle for recording asset retirement obligation (net of tax)		5,854				
Net earnings	$	88,351	21,276	103,743	130,608	19,043
Net earnings attributable to common stock	$	88,351	21,276	103,743	126,440	19,043
Weighted average number of common shares outstanding		49,450	46,935	47,674	46,330	23,971
Basic earnings (loss) per share:						

	Years Ended December 31,				
Earnings attributable to common stock from continuing operations	$ 1.82	.45	2.23	2.44	.85
Loss from discontinued operations (net of tax)	(.15)		(.05)	.29	(.06)
Cumulative effect of change in accounting principle for recording asset retirement obligation (net of tax)	.12				
Earnings attributable to common stock	$ 1.79	.45	2.18	2.73	.79
Diluted earnings (loss) per share:					
Earnings attributable to common stock from continuing operations	$ 1.79	.44	2.16	2.36	.84
Loss from discontinued operations (net of tax)	(.15)		(.05)	.28	(.05)
Cumulative effect of change in accounting principle for recording asset retirement obligation (net of tax)	.11				
Earnings attributable to common stock	$ 1.75	.44	2.11	2.64	.79
Total assets	$ 2,683,548	1,924,681	1,796,369	1,752,378	1,474,689
Long-term debt	$ 929,971	767,219	594,178	622,234	686,153
Other long-term liabilities	$ 294,670	44,576	37,950	31,241	25,112
Shareholders' equity	$ 1,185,798	921,211	923,943	858,966	558,984

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(In Thousands Except Per Share Amounts, Volumes and Prices)				
OPERATING DATA					
Annual production:					
Gas (MMCF)	96,977	92,068	108,394	113,842	61,702
Liquids (MBBLS)	8,701	8,657	10,600	11,427	4,397
Average sales price:					
Gas (per MCF)	$ 4.53	3.13	4.32	3.23	2.18
Liquids (per Barrel)	$ 24.77	21.16	23.31	22.46	13.51
Capital expenditures, net of asset sales(1)	$ 716,554	352,812	416,316	372,688	104,612
Proved Reserves:					
Gas (MMCF)	808,068	813,394	828,549	844,058	825,623
Liquids (MBBLS)	81,324	124,366	119,549	89,241	97,086
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 2,307,930	2,053,148	1,346,653	3,694,431	1,419,022
Prices used in calculating present value at end of year proved reserves:					
Gas (per MCF):					
United States	$ 5.79	4.16	2.66	9.52	2.37
Canada	$ 4.52	3.30	2.06	6.11	1.66
Liquids (per BBL):					
United States	$ 29.89	27.85	17.01	23.84	22.38
Canada	$ 27.84	26.63	15.05	23.59	19.98

(1) Does not include estimated discounted asset retirement obligations of $63.7 million related to assets placed in service during the year ended December 31, 2003.

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, Business Forward-Looking Statements, of this Form 10-K. Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed under the heading " Risk Factors" below and elsewhere in this Form 10-K. Historical statements made herein are accurate only as of the date of filing of this Form 10-K with the Securities and Exchange Commission 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.

Overview

We are an independent oil and gas company engaged in the acquisition, exploration, development and production of natural gas and liquids in North America and selected international locations. 2003 was a year mixed with successes and significant disappointments and a year in which we changed our corporate leadership and strategies.

2003 Highlights:

The successes included:

- better production performance (149 BCFE in 2003 vs. 144 BCFE in 2002),
- significantly higher revenue (primarily as a result of higher production and oil and gas prices),
- lower lease operating expenses ($4.5 million lower in 2003 than 2002 despite a $6 million increase in production and ad valorem taxes),
- significantly higher net income (resulting from higher production, higher realized oil and gas prices and lower expenses),
- continued drilling success on deep shelf prospects in the Gulf of Mexico, and
- acquisitions totaling 322 BCFE of estimated proved reserves in properties located in the Gulf of Mexico, Gulf Coast, South Texas and the Permian Basin. These properties were acquired for a total of $391 million (net of taxes) or $1.22 per MCFE and will add to our production in 2004.

Despite these successes, we experienced disappointing production performance and drilling results in a number of areas, the most significant of which was the Redoubt Shoal Field in the Cook Inlet of Alaska. The total downward revisions of estimated proved reserves taken in 2003 was 473 BCFE, of which approximately 62% was attributable to a downward revision of our estimated proved oil reserves at Redoubt Shoal Field. Proved reserves were 1,296 BCFE at year-end 2003, a year over year reduction of approximately 17%. See " *2003 Reserve Revisions*" below.

In 2003 we also experienced a leadership change and revised our strategies. In the third quarter of 2003, we named a new chief executive officer and split the CEO and Chairman of the Board positions, also naming a new non-executive Chairman. Our new leadership revised our strategies late in the third quarter. We established a four-point plan to achieve increased value for our investors, consisting of:

- a focus on cost control,

- reduced exposure to frontier exploration in favor of lower risk exploitation,

- pursuit of asset acquisitions as an integral part of our investment program, and

- a focus on our financial strength to fund growth.

We implemented our plan in the fourth quarter and acquired 244 BCFE of proved reserves in that quarter. These acquisitions now make up almost 20% of our proved reserve base.

One of these strategies, the focus on our financial strength to fund growth, could be a distinct challenge. Over time, we would like to achieve a debt/capitalization percentage of 30-40%. As of December 31, 2003 our debt/capitalization percentage was 44%. When appropriate, we intend to access capital markets, including equity markets, to finance larger acquisitions and help us achieve our debt/capitalization goals.

2003 Reserve Revisions:

During 2003 we revised downward our estimates of proved reserves by a total of approximately 473 BCFE. The downward revision of our estimates was due to information received from production results, drilling activity and other events that occurred primarily in the latter part of 2003. The revisions are not expected to have a material impact on our near-term hydrocarbon production volumes.

Approximately 62% of the total revisions was attributable to the downward revision of our estimate of proved oil reserves in the Redoubt Shoal Field in the Cook Inlet, Alaska. We reduced our estimate of proved oil reserves associated with our Redoubt Shoal Field in Alaska from our 2002 year-end estimate by approximately 49 million barrels, or approximately 85% of the estimated proved oil reserves of this field as of December 31, 2002. Of this revision, approximately 36 million barrels were classified as proved undeveloped as of December 31, 2002. Our estimate of proved oil reserves attributable to the Redoubt Shoal Field was approximately 8 million barrels as of December 31, 2003.

Cumulative investment in exploration, delineation and development of the Redoubt Shoal Field by Forest and its predecessor, Forcenergy, through December 31, 2003 was approximately $310 million. As of December 31, 2003, we estimated total future development capital expenditures, excluding abandonment, for the Redoubt Shoal Field to be approximately $53 million.

We also had downward revisions in our estimated proved reserves for other properties in the fourth quarter of 2003 totaling approximately 143 BCFE. These revisions were in addition to 36 BCFE of downward revisions to estimated proved reserves taken previously in 2003. These downward revisions are due to a variety of factors, including recent production performance and revised field development plans.

As a result of the revisions:

- Our global borrowing base under our credit facilities was reduced from $575 million at December 31, 2003 to $480 million at March 4, 2004.

- The rating agencies may downgrade our credit rating. In February 2004, following announcement of our downward reserve revisions, Forest was placed on "credit watch" by both rating agencies. A downgrade in our credit rating would increase the cost of amounts borrowed under our credit facility and could increase the cost and/or reduce the availability of any additional long-term debt.

- There could be an increase in the cost or amount of credit support (insurance, letters of credit, bonds) required by our counterparties. We could also be required to agree to stricter debt covenants that would restrict our operating flexibility.

We do not believe that the revisions to our estimates of proved reserves or the effects on our liquidity or financial condition will create an event of non-compliance with any of our debt covenants. See "Liquidity and Capital Resources" below.

As a result of the revisions, we are subject to writedowns of our U.S. and Canadian full cost pools under "ceiling test" limitations pursuant to full cost accounting at higher commodity price thresholds than we were prior to the revisions. If we were to record writedowns, shareholders' equity could be reduced significantly.

2004 Outlook:

In executing our plan in 2004, we face a number of uncertainties and challenges. First, while we hedge the price risk for a portion of our production, oil and gas prices, which have a significant impact on our cash flow remain volatile and uncertain. Also, net income will be adversely impacted by the higher depletion expense resulting from our downward revisions to our estimate of proved reserves in 2003. While we believe that there will be a large number of oil and gas acquisition opportunities in 2004 and that we have the skills to make sound acquisitions, we also believe that the competition for these opportunities will be significant. In addition, we have made and will make changes in 2004 to our organization to enhance productivity. While we believe that these changes, over time, will improve our performance, they could, in the short run, negatively impact performance. The borrowing base under our bank facility has been reduced due to the downward revision of our estimates of proved reserves in 2003. We believe, however, that we have adequate liquidity to accomplish our exploration and development spending plan and to also make a meaningful amount of oil and gas property acquisitions. Forest's anticipated expenditures for exploration and development in 2004 are estimated to range from $275 million to $325 million.

Overall, our outlook for 2004 is a positive one. We have changed our direction with four key strategies. The execution of tactics to accomplish these strategies is well underway. We made two sizeable acquisitions in the fourth quarter of 2003 and we are actively pursuing others. We will reduce frontier exploration spending, and we plan to pursue some high-impact exploration spending. We will continue to emphasize cost control in all areas, including general and administrative costs. If the current favorable oil and gas price environment continues, we expect to generate cash flow in 2004 in excess of our expected capital expenditures. In summary, we will continue to take the necessary actions to accomplish our overall objective to enhance shareholder value and to seek prudent growth.

Results of Operations

Net earnings for 2003 were $88.4 million compared to net earnings of $21.3 million in 2002. The increase in earnings was due primarily to the combination of higher average oil and gas sales prices, higher sales volumes, and lower oil and gas production expense.

Net earnings for 2002 were $21.3 million compared to net earnings of $103.7 million in 2001. The decrease in earnings was the result of lower sales volumes and lower average oil and gas sales prices, offset partially by lower operating expenses. Lower sales volumes were primarily the result of property sales in the fourth quarter of 2001, hurricane downtime in the Gulf of Mexico in 2002 and normal declines caused by reduced capital expenditures.

Oil and Gas Sales

Sales volumes, weighted average sales prices, and oil and gas sales revenue for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Years Ended December 31,				
	2003	% Change	2002	% Change	2001
Natural Gas					
Sales volumes (MMCF):					
United States	84,368		78,543		97,400
Canada	12,609		13,525		10,994

	Years Ended December 31,				
Total	96,977	5%	92,068	(15)%	108,394
Sales price received (per MCF)	$ 4.98		3.01		4.16
Effects of energy swaps and collars (per MCF)(1)	(.45)		.12		.16
Average sales price (per MCF)	$ 4.53	45%	3.13	(28)%	4.32
Liquids					
Oil and condensate:					
Sales volumes (MBBLS)	7,850		7,531		9,219
Sales price received (per BBL)	$ 29.03		24.21		23.82
Effects of energy swaps and collars (per BBL)(1)	(3.71)		(1.72)		.55
Average sales price (per BBL)	$ 25.32		22.49		24.37
Natural gas liquids:					
Sales volumes (MBBLS)	851		1,126		1,381
Average sales price (per BBL)	$ 19.62		12.27		16.21
Total Liquids sales volumes (MBBLS):					
United States	7,686		7,477		9,239
Canada	1,015		1,180		1,361
Total	8,701	1%	8,657	(18)%	10,600
Average sales price (per BBL)	$ 24.77	17%	21.16	(9)%	23.31
Total Sales Volumes (MMCFE)					
United States	130,484		123,405		152,834
Canada	18,699		20,605		19,160
Total	149,183	4%	144,010	(16)%	171,994
Average sales price (per MCFE)(1)	$ 4.39	34%	3.28	(21)%	4.15
Total Oil and Gas Sales (in thousands)					
Natural gas	$ 439,700		288,542		467,767
Oil, condensate and natural gas liquids	215,493		183,198		247,085
Total	$ 655,193	39%	471,740	(34)%	714,852

(1) Commodity swaps and collars were transacted to hedge the price of spot market volumes against price fluctuations. Hedged natural gas volumes were 49,990 MMCF, 36,050 MMCF and 42,870 MMCF in 2003, 2002 and 2001, respectively. Hedged oil and condensate volumes were 4,597,500 barrels, 3,921,500 barrels, and 3,742,500 barrels in 2003, 2002 and 2001, respectively. These arrangements have been designated as cash flow hedges for accounting purposes and, as a result, the effective portion of the net gains and losses were accounted for as increases and decreases of oil and gas sales. The aggregate net gains (losses) related to our cash flow hedges were $(72,863,000), $(1,742,000) and $22,781,000 for the years ended December 31, 2003, 2002 and 2001, respectively. Those arrangements that are not designated as cash flow hedges for accounting

purposes are recorded as non-operating income or expense. Average sales prices have been adjusted to reflect effects of energy swaps and collars.

The increase in oil and gas sales revenue in 2003 compared to 2002 was the result of increased price realizations for both oil and gas, combined with higher sales volumes. In the United States, increases in our sales volumes were attributable primarily to acquisitions made during 2003. In Canada, our sales volumes decreased in 2003 due primarily to higher royalty volumes in the current higher price environment, plant maintenance and the effects of property divestitures in 2002.

The decrease in oil and gas sales revenue in 2002 compared to 2001 was primarily the result of lower product prices and production volumes. Volume decreases were due primarily to the Gulf Coast business unit. Our Gulf of Mexico properties were impacted by the sale of 50% of Forest's interests in the South Marsh Island and Vermilion areas in the fourth quarter of 2001, and also experienced hurricane downtime and normal production declines that were the result of reduced capital expenditures.

Oil and Gas Production Expense

The components of oil and gas production expense for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Years Ended December 31,				
	2003	**% Change**	**2002**	**% Change**	**2001**
			(In Thousands)		
Direct operating expense and workovers	$ 125,212	(5)%	131,153	(15)%	154,048
Product transportation	9,536	(33)%	14,174	(9)%	15,579
Production and ad valorem taxes	19,422	45%	13,372	(20)%	16,623
Total oil and gas production expense	$ 154,170	(3)%	158,699	(15)%	186,250
Oil and gas production expense (per MCFE)	$ 1.03	(6)%	1.10	2%	1.08

Oil and gas production expense includes direct costs incurred to operate and maintain wells and related equipment and facilities, costs of expensed workovers, product transportation costs from the wellhead to the sales point and production and ad valorem taxes. The reduction in 2003 compared to 2002, on both an absolute and a per-unit basis, reflects cost reduction measures employed throughout Forest's operations, offset somewhat by increases in production and ad valorem taxes that were the direct result of higher product sales prices. The decrease in production expense in 2002 compared to 2001 was due primarily to lower direct operating expense.

General and Administrative Expense; Overhead

The following table summarizes the components of total overhead costs incurred during the periods:

	Years Ended December 31,				
	2003	**% Change**	**2002**	**% Change**	**2001**
			(In Thousands)		
Overhead costs capitalized	$ 24,519	(6)%	26,000	21%	21,474
General and administrative costs expensed	36,322	(4)	37,642	29	29,138
Total overhead costs	$ 60,841	(4)%	63,642	26%	50,612

	Years Ended December 31,				
Number of salaried employees at end of year	346	(3)%	356	1%	352

The 4% decrease in overhead costs in 2003 resulted primarily from cost reduction measures in corporate areas and from higher fixed rate overhead recoveries. Cost reductions were achieved despite the inclusion of approximately $3.6 million attributable to severance costs and termination of the Canadian defined benefit pension plan. The 26% increase in 2002 compared to 2001 was attributable primarily to increases in employee related expenses, legal expense and insurance expense, lower fixed rate overhead cost recoveries for production operations as a result of the Gulf of Mexico property sale and the related change in operatorship of those properties, and lower fixed rate overhead cost recoveries for drilling activities due to decreased capital spending in the 2002 period. The percentage of overhead capitalized remained relatively constant, ranging between 40% and 42% for 2003, 2002 and 2001.

Merger and Seismic License Costs

Merger and seismic licensing costs of $9.8 million in 2001 included banking, legal, accounting, printing and other consulting costs related to the merger with Forcenergy in December, 2000, including severance paid to terminated employees, office closures, employee relocation, data migration, systems integration and costs of transferring seismic licenses from Forcenergy to Forest.

Depreciation and Depletion; Impairments

Depreciation and depletion expense for the years ended December 31, 2003, 2002 and 2001 was as follows:

	Years Ended December 31,				
	2003	**% Change**	**2002**	**% Change**	**2001**
	(In Thousands)				
Depreciation and depletion expense	$ 234,822	27%	185,288	(17)%	224,176
Depletion expense per MCFE	$ 1.55	23%	1.26	(2)%	1.29

The 27% increase in depletion expense and the 23% increase in the per-unit depletion rate in 2003 compared to 2002 were due primarily to downward revisions in estimated proved reserves totaling approximately 473 BCFE in 2003. These revisions, which occurred primarily in the fourth quarter of 2003, resulted in a fourth quarter depletion rate of $2.00 per MCFE. The 17% decrease in depletion expense in 2002 compared to 2001 was attributable primarily to lower production volumes.

At December 31, of the years listed below Forest had the following costs of undeveloped properties which were not subject to depletion:

	United States	**Canada**	**International**	**Total**
	(In Thousands)			
2003	$ 66,339	34,922	56,747	158,008
2002	$ 77,863	27,240	66,533	171,636
2001	$ 86,460	48,577	51,577	186,614

In 2003, Forest recorded impairments of oil and gas properties located outside of North America of $16.9 million ($10.5 million net of taxes), related primarily to evaluations of projects in Albania, Italy, Romania, Switzerland and Tunisia. Of this amount, approximately $10.3 million related to our 35% interest in a project in Albania. No impairments were recorded in 2002. In 2001, Forest recorded impairments of oil and gas properties located outside North America of $18.1 million ($11.2 million net of taxes). Of this amount, approximately $10.0 million ($6.2 million net of taxes) related to Albania.

Impairments were also recognized in other countries in 2001 based on expiration of certain concessions and evaluations of projects in those countries.

Accretion of Asset Retirement Obligation

Accretion expense of approximately $13.8 million was related to the accretion of Forest's asset retirement obligation pursuant to SFAS No. 143, adopted January 1, 2003. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Using a cumulative effect approach, in the first quarter of 2003 Forest recorded an increase to net property and equipment of approximately $102.3 million (net of tax), an asset retirement obligation liability of approximately $96.5 million (net of tax) and an after tax credit of approximately $5.9 million for the cumulative effect of the change in accounting principle.

Other Expense, Net

The components of other expense, net for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Years Ended December 31,		
	2003	**2002**	**2001**
		(In Thousands)	
Loss on extinguishment of debt	$ 3,975	5,262	6,066
Franchise taxes	1,679	1,080	1,420
Forest's share of (income) loss of equity method investee	2,043	(30)	2,460
Foreign currency translation losses (gains) on subordinated debt		(332)	7,872
Realized and unrealized losses (gains) on derivative instruments	(383)	2,041	(11,932)
Write-off of receivables due from Enron for physical sales of natural gas			8,305
Other	(350)	(339)	(2,594)
Total other expense	$ 6,964	7,682	11,597

Losses on extinguishment of debt relate to redemptions of our 8$^3/_4$% and our 10$^1/_2$% Senior Subordinated Notes for amounts in excess of par value. Franchise taxes are paid to the states of Texas and Louisiana based on capital investment deployed in these states, determined by apportioning total capital as defined by law. Forest's share of income or loss of equity method investee relates to our 40% ownership of a pipeline company that transports our crude oil in Alaska. Foreign currency translation gains and losses relate to the translation of U.S. dollar-denominated notes issued by Canadian Forest. All of the outstanding notes were redeemed in September 2002.

Interest Expense

Interest expense of $49.3 million in 2003 was 2% lower than 2002, primarily because the effects of higher average debt balances were more than offset by lower average interest rates on variable and fixed rate debt and by amortization of gains recognized on termination of interest rate swaps. Interest expense of $50.4 million in 2002 was 1% higher than 2001 due primarily to debt balances that were, on average, 19% higher, offset partially by significantly lower interest rates on variable and fixed rate debt.

Current and Deferred Income Tax Expense

Forest recorded current income tax expense of $693,000 in 2003 compared to $228,000 in 2002 and $2.4 million in 2001. The increase in 2003 compared to 2002 was due primarily to changes in the Federal Alternative Minimum Tax and the exhaustion of certain state net operating losses. The decrease in 2002 compared to 2001 was due primarily to decreases in pre-tax profitability and reduced state tax provisions.

Deferred income tax expense was $53.9 million in 2003 compared to $11.8 million in 2002, and $76.9 million in 2001. The increase in 2003 compared to 2002 was attributable to increased pre-tax profitability and an increase in permanent tax differences, partially offset by a decrease in Canadian taxes of $7,332,000 due to a Canadian federal income tax rate reduction from 28% to 21% over a five year period beginning in 2003. The decrease in 2002 compared to 2001 was due primarily to lower pre-tax profitability.

Results of Discontinued Operations

On March 1, 2004, the assets and business operations of our Canadian marketing subsidiary, ProMark, were sold to Cinergy for $11.2 million CDN. Under the terms of the purchase and sale agreement, Cinergy will market natural gas on behalf of Canadian Forest for five years, unless subject to prior contractual commitments, and will also administer the netback pool formerly administered by ProMark. We could receive additional contingent payments over the next five years if Cinergy meets certain earnings goals with respect to the acquired business. As a result of Forest's fourth quarter 2003 decision to sell the gas marketing operations of ProMark, ProMark's results of operations have been reported as discontinued operations in the consolidated statements of operations for all years presented. The components of (loss) income from discontinued operations for the years ended December 31, 2003, 2002 and 2001 are as follows:

	Years Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Marketing income, net	$ 2,728	2,825	3,550
General and administrative expense	(1,921)	(1,484)	(1,376)
Interest income (expense)	(59)		111
Other income, net	606	9	
Depreciation	(1,325)	(933)	(1,857)
Impairment of contract value			(3,239)
Current income tax benefit (expense)	27	(40)	(2)
Deferred income tax expense	(2,623)	(184)	119
Loss on sale of discontinued operations	(5,164)		
	$ (7,731)	193	(2,694)

Liquidity and Capital Resources

Liquidity is a measure of a company's ability to access cash. We have historically addressed our long-term liquidity requirements through the use of bank credit facilities and cash provided by operating activities as well as through the issuance of debt and equity securities, when market conditions permit. The prices we receive for future oil and natural gas production and the level of production have significant impacts on operating cash flows. We are unable to predict with any degree of certainty the prices we will receive for our future oil and gas production.

We continually examine alternative sources of long-term capital, including bank borrowings, the issuance of debt instruments, the sale of common stock, preferred stock or other equity securities, sales of non-strategic assets, prospects and technical information and joint venture financing. Availability of these sources of capital and, therefore, our ability to execute our operating strategy will depend upon a number of factors, some of which are beyond our control.

In 2003, we revised downward our estimates of proved reserves by 473 Bcfe. As a result of the revisions:

Our global borrowing base under our credit facilities was reduced from $575 million at December 31, 2003 to $480 million at March 4, 2004.

The rating agencies may downgrade our credit rating. A downgrade in our credit rating would increase the cost of amounts borrowed under our credit facility and could increase the cost and/or reduce the availability of any additional long-term debt. We could also be required to agree to stricter debt covenants that would restrict our operating flexibility.

There could be an increase in the cost or amount of credit support (insurance, letters of credit, bonds) required by our counterparties.

We do not believe that the revisions to our estimates of proved reserves or the effects on our liquidity or financial condition will create an event of non-compliance with any of our debt covenants.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. It is not unusual for Forest to have deficits in working capital, exclusive of the effects of derivatives and abandonment liabilities, at the end of a period. Such working capital deficits are principally the result of accounts payable related to exploration and development costs. Settlement of these payables is funded by cash flow from operations or, if necessary, by drawdowns on bank credit facilities.

Forest had a working capital deficit, exclusive of the after-tax effects of derivatives and abandonment liabilities, of approximately $11.8 million at December 31, 2003 compared to a corresponding deficit of approximately $15.2 million at December 31, 2002. The change was due primarily to an increase in accounts receivable offset partially by an increase in accounts payable and a decrease in other current assets.

The increases in both accounts receivable and accounts payable are primarily attributable to revenue and joint interest operations resulting from higher product prices and recent acquisitions. The decrease in current assets relates primarily to decreases in cash calls outstanding and prepaid taxes.

Cash Flow. Historically, one of our primary sources of capital has been net cash provided by operating activities. Net cash provided by operating activities, net cash used by investing activities and net cash provided (used) by financing activities for the years ended December 31, 2003, 2002 and 2001 were as follows:

	Years Ended December 31,				
	2003	**% Change**	**2002**	**% Change**	**2001**
	(In Thousands)				
Net cash provided by operating activities	$ 381,984	100%	190,772	(62)%	500,810
Net cash used by investing activities	(659,181)	85%	(356,613)	(16)%	(423,656)
Net cash provided (used) by financing activities	274,549	61%	170,828	310%	(81,533)

The increase in net cash provided by operating activities in 2003 compared to 2002 was due primarily to higher average oil and gas prices. The increase in cash used by investing activities in 2003 was due primarily to the acquisition of certain oil and natural gas properties in October 2003, and the purchase of 100% of the stock of a private company on December 31, 2003. Net cash provided by financing activities in 2003 included net bank borrowings of $197.5 million and net proceeds from the issuance of common stock and the exercise of options and warrants of approximately $141.8 million in the aggregate, partially offset by cash used for the redemption of the $10^1/_2$% Senior Subordinated Notes of $69.4 million in the aggregate. The 2002 period included net borrowings of bank debt of $75.4 million, proceeds from the settlement of interest rate swaps of $35.6 million and net proceeds of $146.8 million from the issuance of the $7^3/_4$% Senior Notes, offset by repurchases of the $10^1/_2$% Senior

Subordinated Notes of $23.9 million in the aggregate and repurchases and redemptions of the $8^3/_4$% Senior Subordinated Notes of $66.2 million in the aggregate.

The decrease in net cash provided by operating activities in 2002 compared to 2001 was due primarily to lower product prices and decreased production. The decrease in cash used for investing activities in 2002 compared to 2001 was due primarily to decreased exploration and development activity in 2002, offset partially by lower property sales in 2002 compared to 2001. Net cash provided by financing activities in 2002 included net bank debt borrowings of $75.4 million, proceeds from the settlement of interest rate swaps of $35.6 million and net proceeds of $146.8 million from the issuance of the 7 3/4% Senior Notes, offset by repurchases of the 10 1/2% Senior Subordinated Notes of $23.9 million and repurchases and redemptions of the 8 3/4% Senior Subordinated Notes of $66.2 million in the aggregate. The 2001 period included net repayments of bank debt of $313.6 million, cash used for redemption of 8 3/4% Senior Subordinated Notes of $131.9 million, cash used for the purchase of treasury stock of $55.8 million, and net cash proceeds of $420.6 million in the aggregate from the issuance of two series of 8% Senior Notes.

Capital Expenditures. Expenditures for property acquisition, exploration and development were as follows:

	Years Ended December 31,		
	2003	2002	2001
		(In Thousands)	
Property acquisition costs:			
Proved properties	$ 420,022	3,938	31
Undeveloped properties	4,223	(13)	
	424,245	3,925	31
Exploration costs:			
Direct costs	90,715	89,117	214,194
Overhead capitalized	13,549	13,246	9,820
	104,264	102,363	224,014
Development costs:			
Direct costs	189,269	235,177	328,962
Overhead capitalized	10,970	12,755	11,654
	200,239	247,932	340,616
Total capital expenditures for property development, acquisition and exploration(1)	$ 728,748	354,220	564,661

(1) Does not include estimated discounted asset retirement obligations of $63.7 million related to assets placed in service during the year ended December 31, 2003.

Forest's anticipated expenditures for exploration and development in 2004 are estimated to range from $275 million to $325 million. We intend to meet our 2004 capital expenditure financing requirements using cash flows generated by operations, sales of assets and, if necessary, borrowings under bank credit facilities. There can be no assurance, however, that we will have access to sufficient capital to meet these capital requirements. The planned levels of capital expenditures could be reduced if we experience lower than anticipated net cash provided by operations or develop other needs for liquidity, or could be increased if we experience increased cash flow or access additional sources of capital.

In addition, while we intend to continue a strategy of acquiring reserves that meet our investment criteria, no assurance can be given that we can locate or finance any property acquisitions.

Bank Credit Facilities. We have credit facilities totaling $600 million, consisting of a $500 million U.S. credit facility through a syndicate of banks led by JPMorgan Chase and a $100 million Canadian credit facility through a syndicate of banks led by JPMorgan Chase Bank, Toronto Branch. The credit facilities mature in October 2005. In October 2003, we amended the credit facilities to allow us the option of electing to have availability under the credit facilities governed by a borrowing base (Global Borrowing Base), rather than financial covenants. We can exercise the option one time per year and any such election will be irrevocable for a period of one year. The determination of the Global Borrowing Base is made by the lenders taking into consideration the estimated value of our oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. Effective October 30, 2003, we elected to determine availability based on the Global Borrowing Base. Under the Global Borrowing Base, availability will be re-determined semi-annually and the available borrowing amount could be increased or reduced. In addition, Forest and the lenders each have discretion at any time, but not more than once during any calendar year, to have the global borrowing base redetermined. The recent redetermination will not limit these discretionary redeterminations.

If a borrowing base redetermination is less than the outstanding borrowings under the credit facilities, we would be required to repay the amount representing the excess of outstanding borrowings within a prescribed period. If we were unable to pay the excess amount, it would cause an event of default.

In March 2004, in conjunction with the significant downward revisions to our estimated proved oil and gas reserves, we redetermined the Global Borrowing Base. Effective March 4, 2004, the Global Borrowing Base was set at $480 million, with $460 million allocated to the U.S. credit facility and $20 million allocated to the Canadian credit facility. Under the terms of the credit facility, the Global Borrowing Base will next be redetermined in the second quarter of 2004 and the amount of available borrowing could be adjusted at that time.

At December 31, 2003, the unused borrowing amount under the Global Borrowing Base was approximately $276 million in addition to amounts outstanding. On March 4, 2004, after the borrowing base redetermination, our unused borrowing amount was approximately $165 million in addition to amounts outstanding.

At December 31, 2003, there were outstanding borrowings of $291 million under the U.S. credit facility and $1.5 million under the Canadian credit facility, at a weighted average interest rate of 2.36%. In addition to outstanding borrowings under Forest's credit facilities, there were outstanding borrowings in the amount of $30 million under a small credit facility of an acquired company. That facility was repaid and terminated January 2, 2004, using additional borrowings under Forest's U.S. credit facility. At March 4, 2004, there were outstanding borrowings of $309 million under the U.S. credit facility at a weighted average interest rate of 2.31% and there were no borrowings under the Canadian credit facility. At December 31, 2003, we had used the credit facilities for letters of credit in the amount of $5.7 million. At March 4, 2004, we had used the credit facilities for letters of credit in the amount of $5.5 million.

The credit facilities include terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, and mergers and acquisitions, and include financial covenants. Interest rates and other terms of borrowing under the credit facilities will vary based on our credit ratings and financial condition, as governed by certain financial tests. In particular, any time that availability is not governed by the Global Borrowing Base, the amount available and our ability to borrow under the credit facility is determined by the financial covenants. Under the Global Borrowing Base, the financial

covenants can still affect the amount available and our ability to borrow amounts under the credit facility.

In addition, the credit facilities are collateralized by our assets. The U.S. credit facility is secured by a lien on, and a security interest in, a portion of our proved oil and gas properties and related assets in the United States and Canada, a pledge of 65% of the capital stock of Canadian Forest and its parent, 3189503 Canada Ltd., and a pledge of 100% of the capital stock of Forest Pipeline Company. The Canadian credit facility is secured by a lien on the assets of Canadian Forest. Under certain circumstances, we could be obligated to pledge additional assets as collateral.

Credit Ratings. Our bank credit facilities and our senior notes are separately rated by two ratings agencies: Moody's and S&P. In addition, Moody's and S&P have assigned Forest a general corporate credit rating. From time to time, our assigned credit ratings may change. In assigning ratings, the ratings agencies evaluate a number of factors, such as our industry segment, volatility of our industry segment, the geographical mix and diversity of our asset portfolio, the allocation of properties and exploration and drilling activities among short-lived and longer-lived properties, the need and ability to replace reserves, our cost structure, our debt and capital structure and our general financial condition and prospects.

As a result of the significant downward reserve revisions to our estimated proved resrves in 2003, the rating agencies may downgrade our credit rating. In February 2004, following the announcement of our downward revisions to our estimates of proved oil and gas reserves, Forest was placed on "credit watch" by both ratings agencies.

Our bank credit facilities include conditions that are linked to our credit rating. The fees and interest rates on our commitments and loans, as well as our collateral obligations, are affected by our credit ratings. The agreements governing our senior notes do not include adverse triggers that are tied to our credit ratings. The terms of our senior notes include provisions that will allow us greater flexibility if the credit ratings improve to investment grade and other tests have been satisfied. In this event, we would have no further obligation to comply with certain restrictive covenants contained in the indentures governing the senior notes. Our ability to raise funds and the costs of such financing activities may be affected by our credit rating at the time any such activities are conducted.

Dispositions of Assets. As a part of our ongoing operations, we routinely dispose of non-strategic assets. Assets with marginal value or which are not consistent with our operating strategy are identified for sale or trade.

During 2003, we disposed of properties with estimated proved reserves of approximately 7.4 BCF of natural gas and 2,303,000 barrels of oil for total proceeds of approximately $14,445,000. During 2002, we disposed of properties with estimated proved reserves of approximately 3.4 BCF of natural gas and 738,000 barrels of oil for total proceeds of approximately $5,465,000. During 2001, we disposed of properties with estimated proved reserves of approximately 69.8 BCF of natural gas and 4,868,000 barrels of oil for total proceeds of approximately $152,872,000. Of this amount, approximately $118,000,000 related to properties located in the offshore Gulf of Mexico area in which we sold 50% of our interests in connection with a strategic joint venture program.

On March 1, 2004 we sold the gas marketing assets of ProMark to Cinergy. Cinergy will administer on a prospective basis the Canadian Netback Pool. For further information see Part I, Item 1, Business Sales and Markets, of this Form 10-K.

Common Stock Offerings. In October 2003, Forest issued 5,123,000 shares of common stock at a price of $23.10 per share. Net proceeds from this offering were approximately $112,600,000 after deducting underwriting discounts and commissions and estimated offering expenses. Forest used the net proceeds from the offering to fund a portion of the acquisition of properties from Unocal.

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In January 2003, we issued 7,850,000 shares of common stock at a price of $24.50 per share. Net proceeds from this offering (before any exercise of the underwriters' over-allotment option), were approximately $184,400,000 after deducting underwriting discounts and commissions and the estimated expenses of the offering. Forest used the net proceeds from the offering to repurchase, immediately following the closing of the offering, 7,850,000 shares from The Anschutz Corporation and certain of its affiliates. The shares repurchased were cancelled immediately upon repurchase. In February 2003, an additional 900,000 shares of common stock were issued pursuant to exercise of the underwriters' over-allotment option. The net proceeds of $21,168,000 were used for general corporate purposes.

Securities Redeemed and Repurchased. In January 2003 we redeemed the remaining $65,970,000 outstanding principal amount of our $10^1/_2$% Senior Subordinated Notes at 105.25% of par value, resulting in a loss of $3,975,000 recorded in the first quarter of 2003.

Contractual Obligations. The following table summarizes our contractual obligations as of December 31, 2003:

		2004	2005	2006	2007	2008	After 2008	Total
					(In Thousands)			
Bank debt(1)	$	30,000	292,542					322,542
Other long-term debt(2)						265,000	310,000	575,000
Operating leases(3)		5,166	4,292	2,111	1,338	893	848	14,648
Unconditional purchase obligations(4)		21,004	17,744	13,283	1,743	1,563	1,529	56,866
Approved capital projects(5)		13,449						13,449
Total contractual obligations	$	69,619	314,578	15,394	3,081	267,456	312,377	982,505

(1) Bank debt consists of $292.5 million related to our U.S. and Canadian credit facilities and $30 million of bank debt assumed in conjunction with our acquisition of a private company on December 31, 2003. The bank debt assumed in the acquisition was

subsequently paid on January 2, 2004 with proceeds from our U.S. credit facility. For a more detailed discussion of our long-term debt, see Item 7A, Quantitative and Qualitative Disclosures About Market Risk Interest Rate Risk and Note 4 of Notes to Consolidated Financial Statements.

(2) Other long-term debt consists of our senior notes. For a more detailed discussion of our long-term debt, see Item 7A, Quantitative and Qualitative Disclosures About Market Risk Interest Rate Risk and Note 4 of Notes to Consolidated Financial Statements.

(3) Consists primarily of leases for office space and leases for well equipment rentals.

(4) Consists primarily of firm commitments for gathering, processing and pipeline capacity. Gathering, processing and pipeline capacity commitments in areas that have secondary markets may be mitigated in the future if firm capacities are no longer required. Canadian Forest, on behalf of the Canadian Netback Pool, has firm commitments for pipeline capacity of approximately $44,646,000 through 2009. Canadian Forest, as one of the producers in the Canadian Netback Pool, supplied 42% of the gas to the Canadian Netback Pool in 2003.

(5) Consists of our net share of budgeted expenditures under Authorizations for Expenditure (AFEs) that were approved by us and our joint venture partners as of December 31, 2003. Includes AFEs for which Forest is the operator as well as those operated by others.

In addition to the above commitments, we are committed to make approximately $38.5 million of capital expenditures over the next five years pursuant to the terms of foreign concession arrangements and an exploration agreement in Canada. Nonperformance under these agreements could result in the loss of acreage and concession rights. We also have other long-term liabilities of approximately $24.1 million, primarily related to benefit obligations for which neither the ultimate settlement amounts

nor timing of payment can be precisely determined in advance. As of December 31, 2003, $22.1 million of assets were held in trust to satisfy these obligations.

Forest also makes delay rental payments to lessors during the primary terms of oil and gas leases to delay drilling of wells, usually for one year. Although we are not obligated to make such payments, discontinuing them would result in the loss of the oil and gas lease. Our total maximum commitment under these leases, through 2014, totaled approximately $6.3 million as of December 31, 2003.

Estimated costs related to future abandonment liabilities are recorded on our balance sheet. There are currently no contractual obligations related to these costs.

Off-balance Sheet Arrangements. We have no off-balance sheet arrangements.

Other Obligations. We hold a 40% equity interest in an affiliate that owns a petroleum pipeline system within the Cook Inlet area of Alaska. In our capacity as a shareholder, we have agreed to fund our proportionate share of the operating costs and expenses of this affiliate. We may have contingent obligations in the event the affiliate experiences cash deficiencies. In addition, we may have other contingent obligations if the affiliate is unable to meet its indemnification requirements or its obligations to the operator of the pipeline. We are unable to predict or quantify the amount of these obligations, although we have obtained insurance to mitigate the impacts of certain possible outcomes.

Surety Bonds. In the ordinary course of our business and operations, we are required to post surety bonds from time to time with third parties, including governmental agencies. As of February 28, 2004, we have obtained surety bonds from a number of insurance and bonding institutions covering certain of our operations in the United States and Canada in the aggregate amount of approximately $31,896,000. In connection with their administration of offshore leases in the Gulf of Mexico, the MMS annually evaluates each lessee's plugging and abandonment liabilities. The MMS reviews this information and applies certain financial tests including, but not limited to, current asset and net worth tests. The MMS determines whether each lessee is financially capable of paying the estimated costs of such plugging and abandonment liabilities. We annually provide the MMS with our financial information. If we do not satisfy the MMS requirements, we could be required to post supplemental bonds. In the past, Forest has not been required to post supplemental bonds; however, we cannot assure you that we will satisfy the financial tests and remain on the list of MMS lessees exempt from the supplemental bonding requirements. We cannot predict or quantify the amount of any such supplemental bonds or the annual premiums related thereto, but the amount could be substantial. See Part I, Regulation in this Form 10-K for further information.

As a result of the significant downward revisions in our estimated proved reserves in 2003, there could be an increase in the cost of and/or the amount of credit support (insurance, letters of credit, bonds) required by our counterparties.

Critical Accounting Policies, Estimates, Judgments and Assumptions

Alternatives exist among accounting methods we use to report our financial results. The choice of an accounting method can have a significant impact on reported amounts. In addition, application of generally accepted accounting principles requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements as well as the revenues and expenses reported during the period. Changes in these estimates, judgments and assumptions will occur as a result of future events, and, accordingly, actual results could differ from amounts estimated.

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

obligations used in such calculations. Assumptions, judgments and estimates are also required in determining impairments of undeveloped properties, the valuation of deferred tax assets, and the estimation of fair values for derivative instruments.

The use of estimates, judgments and assumptions and the potential effects thereof are further described in " Risk Factors Estimates of oil and gas reserves are uncertain and inherently imprecise" in this Item 7 and in Notes to Consolidated Financial Statements.

Full Cost Method of Accounting. We use the "full cost method" of accounting for our oil and gas operations. Separate cost centers are maintained for each country in which we incur costs. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and overhead related to exploration and development activities) are capitalized. The fair value of estimated future costs of site restoration, dismantlement and abandonment activities is capitalized, with a corresponding asset retirement obligation liability recorded. Capitalized costs applicable to each full cost center are depleted using the units of production method based on conversion to common units of measure using one barrel of oil as an equivalent to six thousand cubic feet of natural gas. Changes in estimates of reserves or future development costs are accounted for prospectively in the depletion calculations. Assuming consistent production year over year, our depletion expense will be significantly higher or lower if we significantly decrease or increase our estimates of remaining proved reserves.

Investments in unproved properties, including related capitalized interest costs, if any, are not depleted pending the determination of the existence of proved reserves. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized in the appropriate full cost pool.

Where proved reserves are established, the net capitalized costs of oil and gas properties may not exceed a "ceiling limitation" which is based on the present value of estimated future net cash flows from proved reserves including the effects of derivative instruments, discounted at 10%, plus the lower of cost or estimated fair value of unproved properties, all net of expected income tax effects. To the extent the net capitalized costs of oil and gas properties exceed the ceiling limit, the excess is charged to earnings.

Changes in estimates of discounted future net revenues will affect the calculation of the ceiling limitation. We did not have any writedowns related to the full cost ceiling limitation in 2003, 2002 or 2001. As of December 31, 2003, the ceiling limitation exceeded the carrying value of our oil and gas properties by approximately $410 million in the U.S. and $13.1 million (CDN) in Canada. Estimates of discounted future net cash flows at December 31, 2003 were based on average natural gas prices of approximately $5.79 per MCF in the U.S. and approximately $4.52 per MCF in Canada and on average liquids prices of approximately $29.89 per barrel in the U.S. and approximately $27.84 per barrel in Canada. A reduction in oil and gas prices and/or estimated quantities of oil and gas reserves would reduce the ceiling limitation in the U.S. and Canada and could result in a ceiling test writedown. In particular, our Canadian full cost pool could be adversely impacted by moderate declines in commodity prices. In 2003, we revised downward our estimates of proved reserves by 473 BCFE. As a result of the revisions, we are subject to writedowns of our U.S. and Canadian full cost pools under "ceiling test" limitations pursuant to full cost accounting at higher commodity price thresholds than we were prior to the revisions. If we were to record writedowns, shareholders' equity could be reduced significantly.

In countries where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs and other costs incurred during the exploration phase remain capitalized as unproved property costs until proved reserves have been established or until exploration activities cease. If exploration activities result in the establishment of proved reserves, amounts are reclassified as proved properties and become subject to depreciation, depletion and amortization and the application of the ceiling limitation. If exploration efforts are unsuccessful in establishing proved reserves and exploration activities cease, the amounts accumulated as unproved costs are charged against earnings as impairments. As of December 31, 2003, costs related to these international projects of approximately $56.7 million were not being depleted pending determination of the existence of proved reserves. In 2003, we recorded an impairment of $16.9 million ($10.5 million net of taxes) related primarily to concessions in Albania, Italy, Romania, Switzerland and Tunisia. No impairments were recorded in 2002. In 2001, we recorded impairments of $18.1 million ($11.2 million net of tax). Of this amount, approximately $10.0 million ($6.2 million net of taxes) was related to Albania. Impairments were also recognized in other countries based on expiration of certain concessions and evaluations of projects in those countries.

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

We believe the full cost method is the appropriate method to use to account for our oil and gas exploration and development activities, because we conduct significant exploration programs in the Gulf of Mexico, in Canada and in various international regions and the full cost method more appropriately reports the costs of these exploration programs as part of an overall investment in discovering and developing proved reserves.

Fair Values of Derivative Instruments. We periodically hedge a portion of our oil and gas production through swap and collar agreements. The purpose of the hedges is to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk. We recognize the fair value of all derivative instruments as assets or liabilities on the balance sheet. The accounting treatment for the changes in fair value is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative qualifies as an effective hedge. Changes in fair value of cash flow hedges are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. For fair value hedges to the extent the hedge is effective, there is no effect on the statement of operations because changes in fair value of the derivative offset changes in the fair value of the hedged item. For derivative instruments that do not qualify as fair value hedges or cash flow hedges, changes in fair value are recognized in earnings as other income or expense.

The estimation of fair values for our hedging derivatives requires substantial judgment. The fair values of our derivatives are estimated on a monthly basis using an option-pricing model. The option-pricing model uses various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. The estimated future prices are compared to the prices fixed by the hedge agreements, and the resulting estimated future cash inflows (outflows) over the terms of the hedges are discounted using estimated weighted average cost capital. These pricing and discounting variables are sensitive to market volatility as well as to changes in future price forecasts, regional price differentials and interest rates.

Entitlements Method of Accounting for Oil and Gas Sales. We account for oil and gas sales using the "entitlements method." Under the entitlements method, revenue is recorded based upon our ownership share of volumes sold, regardless of whether we have taken our ownership share of such volumes. We record a receivable or a liability to the extent we receive less or more than our share of

the volumes and related revenue. Under the alternative "sales method" of accounting for oil and gas sales, revenue is recorded based on volumes taken by us or allocated to us by third parties, regardless of whether such volumes are more or less than our ownership share of volumes produced. Reserve estimates are adjusted to reflect any overproduced or underproduced positions. Receivables or payables are recognized on a company's balance sheet only to the extent that remaining reserves are not sufficient to satisfy volumes over- or under-produced.

Make-up provisions and ultimate settlements of volume imbalances are generally governed by agreements between Forest and its partners with respect to specific properties or, in the absence of such agreements, through negotiation. The value of volumes over- or under-produced can change based on changes in commodity prices.

The entitlements method of accounting for oil and gas sales allows for recognition of revenue based on Forest's actual share of jointly owned production, and matches revenue with related operating expenses. In addition, it provides balance sheet recognition of the estimated value of product imbalances. As of December 31, 2003 Forest had recorded the following amounts in the accompanying balance sheet related to our gas imbalances:

	Value	Volumes
	(In Thousands)	(MMCF)
Gas imbalance receivable	$ 16,161	5,353
Gas imbalance liability	(12,733)	(5,016)
Net gas imbalance receivable	$ 3,428	337

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

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods which the deferred tax assets are deductible, management believes it is more likely than not that we will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31, 2003. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward periods are reduced.

Impact of Recently Issued Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 141*, Business Combinations* (SFAS No. 141) and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142). SFAS No. 141 addresses accounting and reporting for business combinations and is effective for all business combinations initiated after June 30, 2001. SFAS No. 142 addresses the accounting and reporting for acquired goodwill and other intangible assets. The new standard eliminates the requirement to amortize

acquired goodwill; instead, such goodwill is required to be reviewed at least annually for impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and SFAS No. 142 had no impact on the carrying value of our goodwill or intangible assets.

The Emerging Issues Task Force is currently considering two reporting issues regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the extractive industries, including oil and gas companies. The issues are whether SFAS No. 141 and SFAS No. 142 require registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, we have included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that oil and gas companies are required to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, we would be required to reclassify approximately $40 million to $50 million at December 31, 2003 and approximately $15 million to $20 million at December 31, 2002, out of oil and gas properties and into a separate intangible assets line item. Our total balance sheet, cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules. Further, we do not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on our compliance with covenants under our debt agreements.

Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (SFAS No. 149), was issued in April 2003. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. The adoption of SFAS No. 149 did not have a significant effect on our financial condition or results of operations.

Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS No. 150), was issued May 2003. SFAS No. 150 establishes standards for how an issuer classifies and measures three classes of freestanding financial instruments (mandatorily redeemable instruments, instruments with repurchase obligations, and instruments with obligations to issue a variable number of shares) with characteristics of both liabilities and equity. Instruments within the scope of the statement must be classified as liabilities on the balance sheet. SFAS No. 150 is effective for all freestanding financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. Forest does not currently hold any financial instruments within the scope of SFAS No. 150.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities* (FIN 46R), which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. FIN 46R replaces FASB Interpretation No. 46, *Consolidation of Variable Interest Entities*, which was issued in January 2003. We will be required to apply FIN 46R to variable interests in variable interest entities (VIEs), if any, created after December 31, 2003. We do not currently own any interests in VIEs; therefore, FIN 46R will not affect our consolidated financial statements.

Risk Factors

Forest has made in this Form 10-K, and may from time to time otherwise make in other public filings, press releases and discussions with management, forward-looking statements within the meaning of

Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements include statements, among others, about Forest's operations, performance and financial results and condition, as described in more detail in Part I, Item 1 of this Form 10-K, under the heading " Forward-Looking Statements." Such statements are subject to risks and uncertainties, and actual results may differ materially from those expressed or implied by the forward-looking statements. Some of these risks and uncertainties are detailed below and elsewhere in this Form 10-K and in Forest's other public filings, press releases and discussions with Forest's management. Forest undertakes no obligation to update or revise any forward-looking statements, except as required by law.

In addition to the information set forth elsewhere in this Form 10-K, the following factors should be carefully considered when evaluating Forest.

Oil and gas price declines could adversely affect Forest's revenue, cash flows and profitability. Prices for oil and natural gas fluctuate widely. Forest's revenues, profitability and future rate of growth depend substantially upon the prevailing prices of oil and natural gas. Increases and decreases in prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow from banks may be subject to redetermination based on changes in prices. In addition, we may have ceiling test write-downs when prices decline. Lower prices may also reduce the amount of oil and natural gas that Forest can produce economically. Any substantial or extended decline in the prices of or demand for oil and natural gas would have a material adverse effect on our financial condition and results of operations.

We cannot predict future oil and natural gas prices. Factors that can cause price fluctuations include:

- relatively minor changes in the supply of and demand for oil and natural gas;
- market uncertainty;

- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political and economic conditions in oil producing countries, particularly those in the Middle East;
- the foreign supply of oil and natural gas;
- the price of oil and gas imports; or
- general economic conditions.

Hedging transactions may limit our potential gains. In order to manage our exposure to price risks in the marketing of our oil and natural gas, we enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of one year or less. While intended to reduce the effects of volatile oil and gas prices, such transactions may limit our potential gains if oil and gas prices rise over the price established by the arrangements. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;

- the counterparties to our future contracts fail to perform under the contracts; or
- a sudden unexpected event materially impacts oil or natural gas prices.

We cannot assure you that our hedging transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. For further information concerning prices, market conditions and energy swap and collar agreements, see Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk of this Form 10-K, and Notes 8 and 10 of Notes to Consolidated Financial Statements.

Certain parties with whom we have long-term and short-term contracts may fail to perform. We have long-term and short-term contracts, including agreements for the sale of oil and natural gas. Parties to these agreements could fail to perform their contractual obligations as a result of circumstances that are beyond our control. Our ability to enforce these contractual obligations may be adversely affected by bankruptcy and other creditors' rights laws. We cannot guarantee that our oil and gas purchasers will not experience material changes in their financial condition that would impact our ability to collect outstanding amounts and efficiently market our oil and gas production.

We may not be able to obtain adequate financing to execute our operating strategy. We have historically addressed our long-term liquidity needs through the use of bank credit facilities and cash provided by operating activities as well as through the issuance of debt and equity securities when market conditions permit. We continue to examine the following alternative sources of long-term capital:

- bank borrowings or the issuance of debt securities;
- the issuance of common stock, preferred stock or other equity securities;
- sales of properties;
- the issuance of nonrecourse production-based financing or net profits interests;
- sales of prospects and technical information; and
- joint venture financing.

The availability of these sources of capital will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, oil and natural gas prices and the value and performance of Forest. We may be unable to execute our operating strategy if we cannot obtain capital from these sources.

We may not be able to fund our planned capital expenditures. We spend and will continue to spend a substantial amount of capital for the development, exploration, acquisition and production of oil and natural gas reserves. Our capital expenditures for exploration and development during 2003 were $305 million, and totaled $350 million and $565 million in 2002 and 2001, respectively. In addition, in 2003 and 2002 we expended $424 million and $4 million, respectively, for oil and gas property acquisitions. We expect such capital expenditures in 2004 to be approximately $275 million to $325 million. If low oil and natural gas prices, drilling or production delays, operating difficulties or other factors, many of which are beyond our control, cause our revenues and cash flows from operations to decrease, we may be limited in our ability to spend the capital necessary to complete our drilling and development program.

In October 2003, we elected to determine availability under our bank credit facility based on a global borrowing base that is re-determined semi-annually, and may be re-determined at other times during a year at the option of the Company or the lenders. In March 2004, we re-determined the global borrowing base due to the significant downward revisions in our estimated proved reserves at December 31, 2003. The global borrowing base was reduced and may be subject to further reductions if

oil and gas prices decline or we have additional downward revisions. See "*Leverage will materially affect our operations*" below.

In addition, if availability under our credit facilities is reduced as a result of a borrowing base limitation or the covenants and financial tests contained in the agreements, our ability to fund our planned capital expenditures could be adversely affected. After utilizing our available sources of financing, we could be forced to raise additional debt or equity proceeds to fund such expenditures. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

A curtailment of capital spending could adversely affect our ability to replace production and our future cash flow from operations.

Estimates of oil and gas reserves are uncertain and inherently imprecise. This Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the Securities and Exchange Commission relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses may vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth. In certain situations, hydrocarbon reservoirs underlying our properties may extend beyond the boundaries of our own acreage to adjacent acreage owned by others. In this case, our properties may also be susceptible to hydrocarbon drainage from production by the operators on those adjacent properties. Also, we may revise estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. Such variances may be material. For example, see our discussion of 2003 reserve revisions in Part I, Item 2, Properties, of this Form 10-K.

At December 31, 2003, approximately 25% of our estimated proved reserves were undeveloped compared to 37% at December 31, 2002. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. In estimating our proved reserves we have assumed that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our oil and gas reserves and the costs associated with these reserves in accordance with generally accepted petroleum engineering and evaluation principles, we cannot assure you that actual costs will not vary from the estimates, that development will occur as scheduled or that the results will be as estimated. See Note 13 of Notes to Consolidated Financial Statements.

You should not assume that the present value of future net cash flows referred to in this Form 10-K is the current market value of our estimated oil and gas reserves. In accordance with Securities and Exchange Commission requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and gas properties will affect the timing of actual future net cash flows from estimated proved reserves and their present value. In addition, the 10% discount factor, which is required by the Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor for Forest. The effective interest rate at various times and the risks associated with Forest or the oil and gas industry in general will affect the appropriateness of the 10% discount factor.

The process of estimating oil and gas reserves is a complex subjective process of estimating underground accumulations of oil and natural gas and their recoverability that cannot be measured in

an exact way. Such process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of such data. Therefore, these estimates are inherently imprecise.

Leverage will materially affect our operations. As of December 31, 2003, our long-term debt was approximately $930 million, including approximately $293 million outstanding under our global bank credit facilities. Our long-term debt represented 44% of our total capitalization at December 31, 2003.

Our level of debt affects our operations in several important ways, including the following:

- a significant portion of our cash flow from operations is used to pay interest on borrowings;

- the covenants contained in the agreements governing our debt limit our ability to borrow additional funds, to dispose of assets, or to pay dividends;

- the global borrowing base and the covenants contained in the agreements governing our debt may affect our flexibility in planning for, and reacting to, changes in business conditions;

- a high level of debt could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and

- the terms of the agreements governing our debt permit our creditors to accelerate payments upon an event of default (including an event of default under other agreements) or a change of control.

In addition, we may alter our capitalization significantly in order to make future acquisitions or develop our properties. These changes in capitalization may increase our level of debt significantly. A high level of debt increases the risk that we may default on our debt obligations.

Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance. General economic conditions and financial, business and other factors affect our operations, our future performance and our ability to raise additional capital. Many of these factors are beyond our control.

If we are unable to repay our debt at maturity out of cash on hand, we could attempt to refinance such debt, or repay such debt with the proceeds of any equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future debt or equity financing will be available to pay or refinance such debt. In October 2003, we elected to determine availability under our bank credit facility based on a global borrowing base that is re-determined semi-annually, and may be re-determined at other times during a year at our option or the lenders. In March 2004, we re-determined the global borrowing base due to the significant downward revisions in our estimated proved reserves at December 31, 2003. The global borrowing base was reduced, may be subject to further reductions if oil and gas prices decline or we have additional downward revisions. If, following such a redetermination, our outstanding borrowings exceed the amount of the re-determined borrowing base, we will be forced to repay a portion of the outstanding borrowings in excess of the re-determined borrowing base. We cannot assure you that we will have sufficient funds to make such repayments. If we are not able to negotiate renewals of our borrowings or to arrange new financing, we may have to sell significant assets. Any such sale would have a material adverse effect on our business and financial results. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, our credit ratings and our value and performance at the time of such offering or other financing. We cannot assure you that any such offering or refinancing can be successfully completed.

Lower oil and gas prices may cause us to record ceiling limitation writedowns. We use the full cost method of accounting to report our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under full cost accounting rules, the net capitalized costs of oil and gas properties may not exceed a "ceiling limit" which is based upon the

present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling test writedown." This charge would not impact cash flow from operating activities, but would reduce our shareholders' equity. The risk that we will be required to write down the carrying value of our oil and gas properties increases when oil and gas prices are low or volatile. In addition, writedowns may occur if we experience substantial downward adjustments to our estimated proved reserves or our undeveloped property values, if estimated future development costs increase or if purchasers cancel long-term contracts for our natural gas production. We cannot assure you that we will not experience ceiling test writedowns in the future. For example, our Canadian full cost pool, in particular, could be adversely impacted by moderate declines in commodity prices.

We may incur significant abandonment costs or be required to post substantial performance bonds in connection with the plugging and abandonment of wells, platforms and pipelines. We are responsible for the costs associated with the plugging of wells, the removal of facilities and equipment and site restoration on our oil and gas properties, pro rata to our working interest. Future liabilities for projected abandonment costs, net of estimated salvage values, are included as a reduction in the future cash flows from our reserves in our reserve reporting. As of December 31, 2003, our estimated discounted asset retirement obligation liability recorded in the balance sheet was approximately $211.4 million, primarily for properties in offshore Gulf of Mexico and Alaska waters. Approximately $20 million of abandonment costs are anticipated to be incurred in 2004, all of which are expected to be funded by cash flow from operations. Estimates of abandonment costs and their timing may change due to many factors, including actual drilling and production results, inflation rates, changes in abandonment techniques and technology, and changes in environmental laws and regulations.

We may not be able to replace production with new reserves. In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics. Many Gulf of Mexico reservoirs experience high decline rates, while the decline rates in long-lived fields in other regions are lower. Production from the Gulf Coast reservoirs represented approximately 58% of our total production in 2003 and is expected to be a greater percentage in 2004. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful exploration and development activities. Forest's future natural gas and oil production is highly dependent upon its level of success in finding or acquiring additional reserves. The business of exploring for, developing or acquiring reserves is capital intensive and uncertain. We may be unable to make the necessary capital investment to maintain or expand our oil and gas reserves if cash flow from operations is reduced and external sources of capital become limited or unavailable. We cannot assure you that our future exploration, development and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs.

Our operations are subject to numerous risks of oil and gas drilling and production activities. Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be found. The cost of drilling and completing wells is often uncertain. Oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

unexpected drilling conditions;

geological irregularities or pressure in formations;

equipment failures or accidents;

weather conditions;

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shortages in labor;

shortages or delays in the delivery of equipment; and

failure to secure necessary regulatory approvals and permits.

The prevailing prices of oil and natural gas also affect the cost of and the demand for drilling rigs, production equipment and related services.

We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable. Drilling activities can result in dry wells and wells that are productive but do not produce sufficient net revenues after operating and other costs.

Our industry experiences numerous operating risks. The exploration, development and production of oil and natural gas involves risks. These operating risks include the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. If any of these industry operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. For example, a substantial portion of our oil and gas operations is located offshore in the Gulf of Mexico. The Gulf of Mexico area experiences tropical weather disturbances, some of which can be severe enough to cause substantial damage to facilities and possibly interrupt production. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

Our international operations may be adversely affected by currency fluctuations and economic and political developments. We have significant oil and gas operations in Canada. The expenses of such operations, which represented approximately 10% of consolidated cash costs of oil and gas operations, are payable in Canadian dollars. Most of the revenue from Canadian natural gas and oil sales, which represented 10% of total oil and gas revenue in 2003, is based upon U.S. dollars price indices. As a result, Canadian operations are subject to the risk of fluctuations in the relative value of the Canadian and U.S. dollars. We have also acquired additional oil and gas assets in other countries. Although there are no material operations in these countries, our foreign operations may also be adversely affected by political and economic developments, royalty and tax increases and other laws or policies in these countries, as well as U.S. policies affecting trade, taxation and investment in other countries. In South Africa we have an interest in offshore properties with the potential for gas production. No proved reserves have been assigned to these properties as commercial sales contracts have not been established. If we are unable to arrange for commercial use of these properties, we may not be able to recoup our investment and will not realize our anticipated financial and operating results for these properties.

Competition within our industry may adversely affect our operations. We operate in a highly competitive environment. Forest competes with major and independent oil and gas companies for the acquisition of desirable oil and gas properties and the equipment and labor required to develop and operate such properties. Forest also competes with major and independent oil and gas companies in the marketing and sale of oil and natural gas. Many of these competitors have financial and other resources substantially greater than ours.

Our future acquisitions may not contain economically recoverable reserves. A successful acquisition of producing properties requires an assessment of a number of factors beyond our control. These

factors include recoverable reserves, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with such assessments, we perform a review of the subject properties, which we believe is generally consistent with industry practices. However, such a review may not reveal all existing or potential problems. In addition, the review will not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every platform or well. Even when a platform or well is inspected, structural and environmental problems are not necessarily discovered. We are not always able to obtain contractual indemnification for pre-closing liabilities, including environmental liabilities. In addition, competition for producing oil and gas properties is intense and many of our competitors have financial and other resources which are substantially greater than those available to us. Therefore, we cannot assure you that we will be able to acquire oil and gas properties that contain economically recoverable reserves or that we will acquire such properties at acceptable prices.

There are uncertainties in successfully integrating our acquisitions. Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and that unforeseen difficulties can arise in integrating operations and systems and retaining and assimilating the employees. In addition, although we perform a diligent review of the properties acquired in connection with such acquisitions in accordance with industry practices, such reviews are inherently incomplete. These reviews may not necessarily reveal all existing or potential problems or permit us to fully assess the deficiencies and potential associated with the properties. Any of these or similar risks could lead to potential adverse short-term or long-term effects on our operating results.

The marketability of our production depends largely upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. Transportation space on such gathering systems and pipelines is occasionally limited and at times unavailable due to repairs or improvements being made to such facilities or due to such space being utilized by other companies with priority transportation agreements. The available capacity, or lack of available capacity, on these systems and facilities, could result in the shutting-in of producing wells or the delay or discontinuance of development plans for properties. Our access to transportation options can also be affected by U.S. federal and state and Canadian regulation of oil and gas production and transportation, general economic conditions, and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the financial impact on Forest could be substantial and could adversely affect our ability to produce and market oil and natural gas.

Our oil and gas operations are subject to various governmental regulations that materially affect our operations. Our oil and gas operations are subject to various U.S. federal, state and local and Canadian federal and provincial governmental regulations. These regulations may be changed in response to economic or political conditions. Matters regulated include permits for discharges of wastewaters and other substances generated in connection with drilling operations, bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning operations, the spacing of wells, and unitization and pooling of properties and taxation. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. In addition, the Federal Oil Pollution Act (OPA), as amended, requires operators of offshore facilities to prove that they have the financial capability to respond to costs that may be incurred in connection with potential oil spills. Under the OPA and other federal and state environmental statutes, owners and operators of certain defined facilities are strictly liable for such spills of oil and other regulated substances, subject to certain limitations. A substantial spill from one of our facilities could have a material adverse effect on our results of operations, competitive position or financial condition. U.S. and non-U.S. laws regulate

production, handling, storage, transportation and disposal of oil and gas, by-products from oil and gas and other substances and materials produced or used in connection with oil and gas operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

We do not pay dividends. We have not declared any cash dividends on our common stock in a number of years and have no intention to do so in the near future. In addition, we are limited in the amount we can pay by our credit facilities and the indentures pursuant to which our subordinated notes were issued.

Our Restated Certificate of Incorporation and By-laws have provisions that discourage corporate takeovers and could prevent shareholders from realizing a premium on their investment. Certain provisions of our Restated Certificate of Incorporation and By-Laws and provisions of the New York Business Corporation Law may have the effect of delaying or preventing a change in control. Our directors are elected to staggered terms. Also, our Restated Certificate of Incorporation authorizes our board of directors to issue preferred stock without shareholder approval and to set the rights, preferences and other designations, including voting rights of those shares as the board may determine. Additional provisions include restrictions on business combinations, the availability of authorized but unissued common stock and notice requirements for shareholder proposals and director nominations. These provisions, alone or in combination with each other and with the rights plan described below, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to shareholders for their common stock.

Our board of directors has adopted a shareholder rights plan. The existence of the rights plan may impede a takeover of Forest not supported by the board of directors, including a proposed takeover that may be desired by a majority of our shareholders or involving a premium over the prevailing market price of our common stock.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

We produce and sell natural gas, crude oil and natural gas liquids for our own account in the United States and Canada. As a result, our financial results are affected when prices for these commodities fluctuate. Such effects can be significant. In order to reduce the impact of fluctuations in prices, we enter into long-term contracts for a portion of our production and use a hedging strategy. Under our hedging strategy, we enter into commodity swaps, collars and other financial instruments. All of our commodity swaps and collar agreements and a portion of our basis swaps in place at December 31, 2003 have been designated as cash flow hedges. These arrangements, which are based on prices available in the financial markets at the time the contracts are entered into, are settled in cash and do not require physical deliveries of hydrocarbons. We periodically assess the estimated portion of our anticipated production that is subject to hedging arrangements, and we adjust this percentage based on our assessment of market conditions and the availability of hedging arrangements that meet our criteria. Hedging arrangements covered 52%, 42%, and 47% of our consolidated production, on an equivalent basis, during the years ended December 31, 2003, 2002 and 2001, respectively.

Long-Term Sales Contracts. A significant portion of Canadian Forest's natural gas production is sold through the Canadian Netback Pool which was administered by ProMark on behalf of Canadian Forest in 2003 and early 2004. At December 31, 2003, the Canadian Netback Pool had entered into fixed price contracts to sell natural gas at the following quantities and weighted average prices:

	Natural Gas	
	BCF	**Contract Price per MCF**
2004	5.5	$ 2.66 CDN
2005	5.5	$ 2.75 CDN
2006	5.5	$ 2.86 CDN
2007	5.5	$ 2.96 CDN
2008	5.5	$ 3.08 CDN
2009	3.0	$ 3.86 CDN
2010	1.7	$ 5.21 CDN
2011	.7	$ 5.50 CDN

The administrator of the Canadian Netback Pool aggregates gas from producers for sale to markets across North America. Currently, in addition to Canadian Forest, over 30 producers have contracted with the Canadian Netback Pool. The producers are paid a netback price which reflects all of the revenue from approved customers less the costs of delivery (including transportation, audit and shortfall makeup costs) and an operator marketing fee.

Canadian Forest, as one of the producers in the Canadian Netback Pool, is obligated to supply its contract quantity. In 2003, Canadian Forest supplied 42% of the total netback pool sales quantity. In the 2004 contract year, it is estimated that Canadian Forest will supply approximately 43% of the Canadian Netback Pool quantity. We expect that Canadian Forest's pro rata obligations as a gas producer will increase in 2005 and future years. In order to satisfy its supply obligations to the Canadian Netback Pool, Canadian Forest may be required to cover its obligations in the market.

The administrator of the Canadian Netback Pool, now Cinergy, is required to acquire gas in the event of a shortfall between the gas supply and market obligations. A shortfall could occur if a gas producer fails to deliver its contractual share of the supply obligations of the Canadian Netback Pool.

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The cost of purchasing gas to cover any shortfall is a cost of the Canadian Netback Pool. The prices paid for shortfall gas would typically be spot market prices and may differ from the market prices received from the customers of the Canadian Netback Pool. Higher spot prices would reduce the average Canadian Netback Pool price paid to the gas producers, including Canadian Forest. Shortfalls in gas produced may occur in the future. We cannot predict with any certainty the amount of any such shortfalls.

In addition to its commitments to the Netback Pool, Canadian Forest is committed to sell natural gas at the following quantities and weighted average prices:

	Natural Gas	
	BCF	Contract Price per MCF
2004	.5	$ 3.95 CDN
2005	.5	$ 4.11 CDN
2006	.4	$ 4.27 CDN

Hedging Program. In a typical commodity swap agreement, Forest receives the difference between a fixed price per unit of production and a price based on an agreed upon published, third-party index if the index price is lower. If the index price is higher, Forest pays the difference. By entering into swap agreements we effectively fix the price that we will receive in the future for the hedged production. Our current swaps are settled in cash on a monthly basis. As of December 31, 2003, Forest had entered into the following swaps accounted for as cash flow hedges:

	Natural Gas		Oil (NYMEX WTI)	
	BBTUs per Day	Average Hedged Price per MMBTU	Barrels per Day	Average Hedged Price per BBL
First Quarter 2004	94.9	$ 5.03	11,850	$ 25.79
Second Quarter 2004	112.3	$ 4.72	12,850	$ 25.70
Third Quarter 2004	112.3	$ 4.72	10,850	$ 25.60
Fourth Quarter 2004	85.7	$ 4.78	6,850	$ 25.90
First Quarter 2005	70.0	$ 4.63	2,500	$ 25.45
Second Quarter 2005	70.0	$ 4.63	2,500	$ 25.45
Third Quarter 2005	70.0	$ 4.63	2,500	$ 25.45
Fourth Quarter 2005	70.0	$ 4.63	2,500	$ 25.45

Between January 1, 2004 and March 5, 2004, we did not enter into any additional swaps accounted for as cash flow hedges.

We also enter into collar agreements with third parties. A collar agreement is similar to a swap agreement, except that we receive the difference between the floor price and the index price only if the index price is below the floor price, and we pay the difference between the ceiling price and the index price only if the index price is above the ceiling price. In addition, Forest has entered into three-way collars with third parties. These instruments establish two floors and one ceiling. Upon settlement, if the index price is below the lowest floor, we receive the difference between the two floors. If the index price is between the two floors, we receive the difference between the higher of the two floors and the index price. If the index price is between the higher floor and the ceiling, we do not receive or pay any additional amounts. If the index price is above the ceiling, we pay the excess over the ceiling price.

Collars are also settled in cash, either on a monthly basis or at the end of their terms. By entering into collars, we effectively provide a floor for the price that we will receive for the hedged production; however, the collar also establishes a maximum price that we will receive for the hedged production if prices increase above the ceiling price. We enter into collars during periods of volatile commodity

prices in order to protect against a significant decline in prices in exchange for foregoing the benefit of price increases in excess of the ceiling price on the hedged production. As of December 31, 2003, Forest had entered into the following gas and oil collars accounted for as cash flow hedges:

	Natural Gas		
	BBTUs Per Day	Average Floor Price per MMBTU	Average Ceiling Price per MMBTU
First Quarter 2004	60.8	$ 4.03	$ 5.77

	Oil (NYMEX WTI)		
	Barrels Per Day	Average Floor Price per BBL	Average Ceiling Price per BBL
First Quarter 2004	2,000	$ 22.00	$ 24.08

Between January 1, 2004 and March 5, 2004, we entered into the following additional collars accounted for as cash flow hedges:

	Natural Gas		
	BBTUs per Day	Average Floor Price per MMBTU	Average Ceiling Price per MMBTU
Fourth Quarter 2004	6.6	$ 5.00	$ 6.70
First Quarter 2005	10.0	$ 5.00	$ 6.70

As of December 31, 2003, Forest had entered into the following 3-way natural gas collars accounted for as cash flow hedges:

	Natural Gas			
	BBTUs per Day	Average Lower Floor Price Per MMBTU	Average Upper Floor Price Per MMBTU	Average Ceiling Price per MMBTU
First Quarter 2004	30.0	$ 3.50	$ 5.27	$ 8.75
Second Quarter 2004	25.0	$ 3.50	$ 4.75	$ 5.80
Third Quarter 2004	25.0	$ 3.50	$ 4.75	$ 5.80
Fourth Quarter 2004	11.7	$ 3.50	$ 4.75	$ 6.14

Between January 1, 2004 and March 5, 2004, we entered into the following additional 3-way collars accounted for as cash flow hedges:

	Oil (NYMEX WTI)			
	Barrels per Day	Average Lower Floor Price per BBL	Average Upper Floor Price per BBL	Average Ceiling Price per BBL
First Quarter 2005	1,500	$ 24.00	$ 28.00	$ 32.00
Second Quarter 2005	1,500	$ 24.00	$ 28.00	$ 32.00

	Oil (NYMEX WTI)						
Third Quarter 2005	1,500	$	24.00	$	28.00	$	32.00
Fourth Quarter 2005	1,500	$	24.00	$	28.00	$	32.00

We also use basis swaps in conjunction with natural gas swaps in order to fix the differential price between the NYMEX price and the index price at which the hedged gas is sold. As of December 31, 2003, Forest had entered into basis swaps designated as cash flow hedges with weighted average volumes of 31.3 BBTUs per day for 2004. Between January 1, 2004 and March 5, 2004, we did not enter into any additional basis swaps designated as cash flow hedges.

The fair value of our cash flow hedges based on the futures prices quoted on December 31, 2003 was a loss of approximately $55,437,000 ($34,433,000 after tax) which was recorded as a component of other comprehensive income.

As of December 31, 2003, Forest had entered into basis swaps that were not designated as cash flow hedges with weighted average volumes of 107.8 BBTUs per day for 2004 and weighted average volumes of 40.0 BBTUs per day for 2005. Between January 1, 2004 and March 5, 2004 we entered into additional basis swaps not designated as cash flow hedges with weighted average volumes of 1.7 BBTUs per day for 2004 and 32.6 BBTUs per day for 2005.

The fair value of our derivative instruments not designated as cash flow hedges based on the futures prices quoted on December 31, 2003 was a gain of approximately $39,000.

Foreign Currency Exchange Risk

We conduct business in several foreign currencies and thus are subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions. In the past, we have not entered into any foreign currency forward contracts or other similar financial instruments to manage this risk. Expenditures incurred relative to the foreign concessions held by Forest outside of North America have been primarily U.S. dollar-denominated, as have cash proceeds related to property sales and farmout arrangements.

Interest Rate Risk

The following table presents principal amounts and related average fixed interest rates by year of maturity for Forest's debt obligations at December 31, 2003:

		2005	2008	2011	2014	Total	Fair Value
		(Dollar Amounts in Thousands)					
Bank credit facilities:							
Variable rate(1)	$	322,542				322,542	322,542
Average interest rate		2.48%				2.48%	
Long-term debt:							
Fixed rate	$		265,000	160,000	150,000	575,000	622,275
Coupon interest rate			8.00%	8.00%	7.75%	7.93%	
Effective interest rate(2)			7.13%	7.48%	6.56%	7.08%	

(1) Includes debt of $30,000,000 with an interest rate of 3.64% at December 31, 2003, which was paid on January 2, 2004. The average interest rate without this debt would have been 2.36%.

(2)

The effective interest rate on the 8% Senior Notes due 2008, the 8% Senior Notes due 2011 and the $7^{3}/_{4}$% Senior Notes due 2014 will be reduced from the coupon rate as a result of amortization of the gains related to termination of related interest rate swaps.

Item 8. Financial Statements and Supplementary Data

Information concerning this Item begins on the following page.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

H. Craig Clark, our Chief Executive Officer, and David H. Keyte, our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K. Based on the evaluation, they believe that:

- our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and

- our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 was accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during our quarterly period ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Independent Auditors' Report

The Board of Directors and Shareholders
Forest Oil Corporation:

We have audited the accompanying consolidated balance sheets of Forest Oil Corporation and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Forest Oil Corporation and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards Nos. 143 and 145; effective January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142; and effective January 1, 2001, the Company adopted the provisions of Statement of Financial Accounting Standards No. 133.

KPMG LLP

Denver, Colorado
March 6, 2004

FOREST OIL CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31,		
	2003		2002
	(In Thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$	11,509	13,166
Accounts receivable		158,954	111,760
Derivative instruments		4,130	3,241
Current deferred tax asset (Note 5)		23,302	10,310
Other current assets		17,465	21,994
Total current assets		215,360	160,471
Net property and equipment, at cost, full cost method (Note 4)		2,433,966	1,687,885
Deferred income taxes (Note 5)			41,022
Assets held for sale related to discontinued operations (Note 3)		8,589	12,525
Other assets		25,633	22,778
	$	2,683,548	1,924,681
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$	192,001	153,413
Accrued interest		3,869	6,857
Derivative instruments		49,838	29,120

	December 31,	
Asset retirement obligation	23,243	
Other current liabilities	4,158	2,285
Total current liabilities	273,109	191,675
Long-term debt (Note 4)	929,971	767,219
Asset retirement obligation	188,189	
Other liabilities	33,758	28,199
Deferred income taxes (Note 5)	72,723	16,377
Shareholders' equity (Notes 4 and 6)		
Common stock, 55,631,924 shares in 2003, (49,125,773 shares in 2002)	5,563	4,913
Capital surplus	1,302,340	1,159,269
Accumulated deficit	(56,495)	(144,548)
Accumulated other comprehensive loss	(9,740)	(41,887)
Treasury stock, at cost, 2,076,731 shares in 2003 (2,101,481 shares in 2002)	(55,870)	(56,536)
Total shareholders' equity	1,185,798	921,211