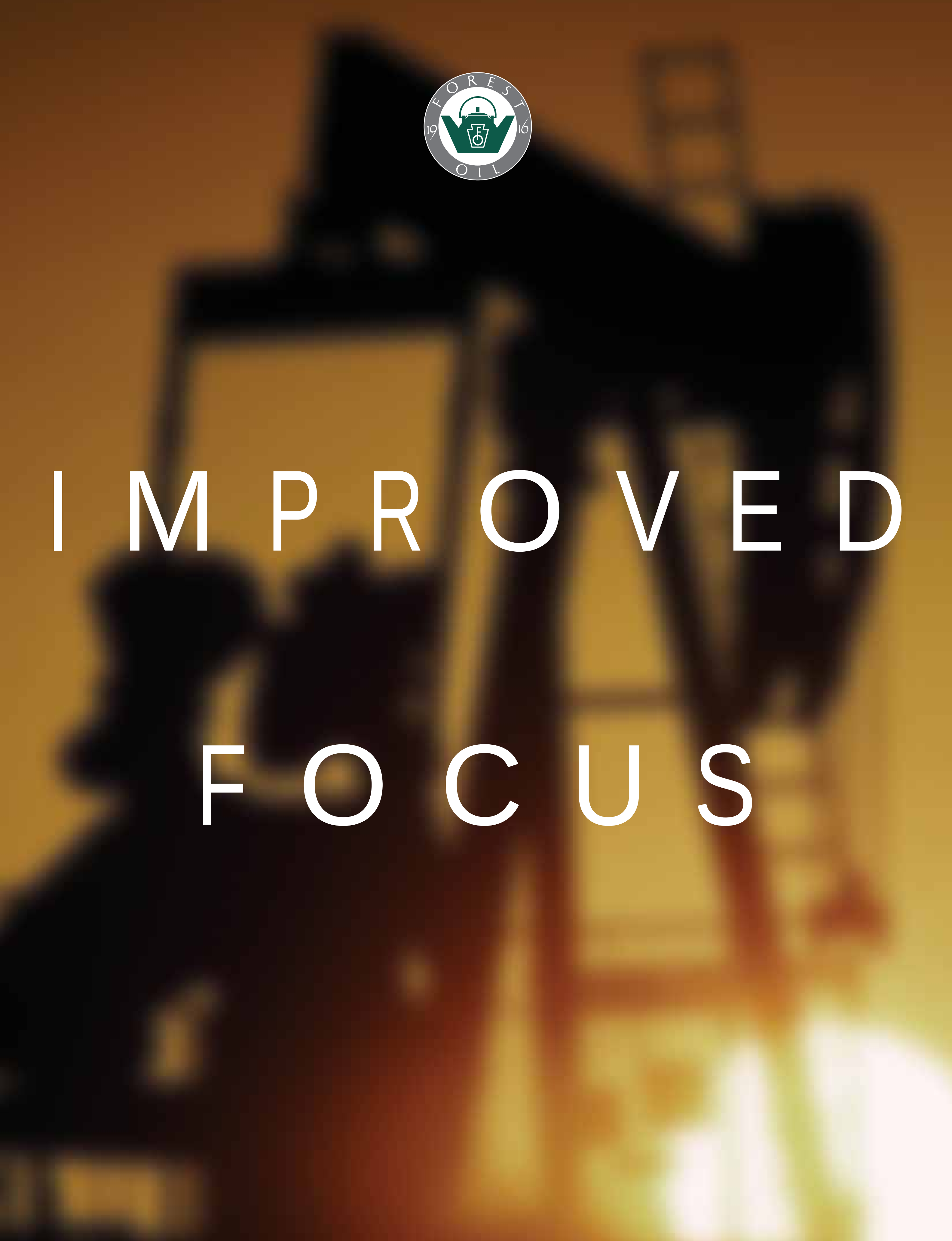


IMPROVED FOCUS

on low-risk development repeatable plays.

ANNUAL REPORT **2005**

On The Move

DEAR FELLOW SHAREHOLDERS As we stated in last year's annual report and in our public presentations throughout the year, our primary goal in 2005 was to further unlock the intrinsic value of our shares on behalf of our shareholders. We certainly believe we accomplished this objective, although our work to drive shareholder returns is ongoing from one year to the next. Forest Oil was among the best performers in our peer group during 2005, which meant new share price highs for our shareholders. Furthermore, a special dividend through the distribution of the Mariner shares to our shareholders in early 2006 will bring additional rewards. ☼ The transaction involving the spin-off of our Gulf of Mexico assets and merger with Mariner Energy is both an innovative transaction in our industry and a highly strategic one for our company. The tax-free nature of the transaction and the direct share distribution illustrate our deal making acumen and deep commitment to our shareholders. The transaction creates attractive portfolios for both companies while allowing each to focus on what they do best — Mariner on exploration in the Gulf of Mexico and Forest on exploitation onshore in North America. ☼ Over the past two years we have successfully completed the transition from an offshore producer with frontier exploration emphasis to a North American onshore producer with numerous low risk opportunities for growth. Our leadership team and employees have performed commendably with the "hand they were dealt". They have executed our 4-Point Strategy to the letter and initiated a series of changes and strategic transactions intended to reshape our portfolio. Through this period of accelerated transition, we steadfastly maintained our commitment to our shareholders and exercised discipline in our choices and investments. We did exactly what we said we would do. The major highlights from 2005 are summarized on the opposite page.

Forrest E. Hoglund Chairman of the Board

H. Craig Clark President and CEO

FUTURE STRATEGY Our new portfolio contains exceptionally high quality assets. We have approximately a dozen growth areas where multiple locations have been identified, comprising an inventory of over 2,000 projects, most of which are not booked in current proven reserves. Further, our company may be somewhat unique in that we also own a significant amount of acreage given our size, enjoy a favorable net operating loss tax position ($506 million net operating loss carry forwards and $198 million of tax pools in Canada) and own several other valuable assets such as our drilling rig fleet. Our project inventory gives us a stable level of activity for years to

2005 HIGHLIGHTS

- ***Announced spin-off of Gulf of Mexico operations to Mariner Energy.***
- ***Forest's Remainco replaced 281 percent of production at an all-source finding cost of $2.16 per Mcfe.***
- ***Continued successful acquisition program with the Buffalo Wallow acquisition at $1.96 per Mcfe.***
- ***Identified 6 significant growth engines for the company.***
- ***Added approximately 50,000 net acres through acquisitions.***
- ***Increased drilling well count to 392 (196 San Juan wells) with 597 total projects completed in 2005.***
- ***Continued business model of free cash flow generation from each producing business unit. No alternative will be tolerated.***
- ***Reduced net debt to capitalization ratio to 33 percent.***

come, complemented by the opportunities generated from the undeveloped acreage which, in turn, should restock the next inventory of projects five to seven years out. Our rig ownership ensures that project timing can be achieved while providing a hedge against future cost increases. Our strategy and future are both simple and highly visible. ☼ Forest's organic growth potential is excellent. We expect growth will occur for multiple years with the same assets that first demonstrated growth in 2005. Fields like Buffalo Wallow in the Texas Panhandle, Wild River in Canada and, more recently, the Cotton Valley assets to be acquired in East Texas, are assets with large upside. Although these areas will carry most of the load for 2006, we have other areas in each business unit that we expect will add to our growth potential. Our exploration success at Haley in West Texas and our Alaska onshore gas program provide early encouragement. ☼ Our two main goals for 2006 are to achieve 10 percent organic production growth and to reduce the company's cost structure following our offshore transaction. We will have attractive organic growth while still maintaining our free cash flow objective. The financial flexibility from free cash flow allows us to reallocate capital and continue to execute the acquire-and-exploit strategy that, as we have demonstrated, works so well for us. ☼ We want to thank the employees of Forest Oil for their hard work and achievements this past year. We want to especially thank the people involved in our offshore transaction and wish all the best to the Forest employees who joined Mariner. We are as committed to them as we are to the employees who were affected by Hurricanes Katrina and Rita. All Forest employees are now shareholders whose interests are aligned with those who invest in our company. Everyone at Forest is as dedicated to the financial success of this company as you are. ☼ In closing, we reiterate what we have emphasized in recent investor presentations: Same Leadership. Same Discipline. Improved Focus. ☼ Our commitment to you remains throughout time. Thank you for your support of our company.

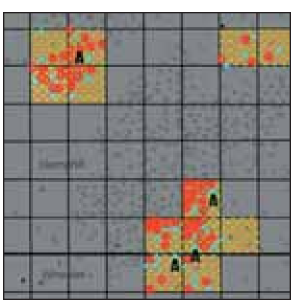
FORREST E. HOGLUND
Chairman of the Board

H. CRAIG CLARK
President and CEO

Operations

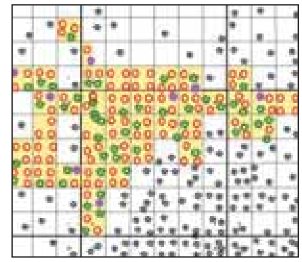
Forest Oil currently has several growth drivers in its portfolio, created from improved focus on its legacy assets and recent acquisitions. Most of these drivers are new to our company over the past two years. The three largest growth drivers for Forest in 2006 will include the Buffalo Wallow Field in the Panhandle of Texas, the Wild River Field in the Deep Basin of Alberta, Canada and the recently announced Cotton Valley transaction in East Texas. Combined, we expect these three projects will yield the majority of the 10 percent organic production growth forecasted for 2006.

BUFFALO WALLOW The acquisition of approximately 120 Bcfe of proved reserves and 370 identified drillsites gave Forest entrance into the prolific natural gas resource play in the Granite Wash trend in the Texas Panhandle. Following an initial review of the portfolio, Forest anticipated per-well costs of $1.4 to $1.9 million, estimated ultimate recoveries of 1.4 to 1.8 Bcfe and initial production rates of 1.5 to 2.0 MMcfe/d. During 2005 these wells were drilled and completed in line with original expectations; however, the initial production rates have increased to an average of 3.6 MMcfe/d. The improved recoveries and higher production rates result from drilling to the deeper Atoka formation, approximately 300 feet beyond the depth originally anticipated, and the utilization of better frac technologies. Forest anticipates these improved results to continue through 2006. As of December 31, 2005, Forest has 329 remaining identified drillsites. The Buffalo Wallow Field has been approved to 20-acre downspacing; Forest has yet to drill to all 40-acre locations. Forest will start 2006 with a four-rig drilling program and anticipates adding a fifth rig in the second quarter. A sixth company-owned rig will be added in the third quarter to enhance 2006 production from this low risk repeatable play and boost overall net production to a targeted 40–45 MMcfe/d for the field.

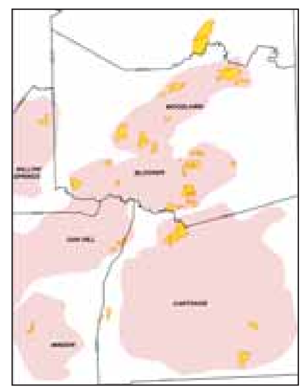


WILD RIVER In 2005, Wild River realized production gains of 278 percent as the field increased net production from a first quarter 2005 exit rate of 9 MMcfe/d to a 2005 exit rate of 25 MMcfe/d. The two-rig drilling program will continue full-throttle into 2006, developing shallow multi-zone stacked gas potential from the Cadomin and other Cretaceous sands. The continued

development program is expected to complete approximately 40 wells during 2006, with drill and completion costs of approximately $2.5 to $3.0 million per well. Initial production rates and estimated ultimate recoveries for 2006 are estimated to average from 1 to 4 MMcfe/d and 1 to 4 Bcfe, respectively. With 160-acre down-spacing and commingling approved in 2005, Forest has approximately 100 down-spacing locations identified as of year-end 2005. Most of these locations are not included in year-end booked reserves. This field has a significant inventory for numerous years to come. This play has a remarkable similarity to the aforementioned Buffalo Wallow Field.



COTTON VALLEY In February of 2006, Forest announced that it will acquire assets located primarily in the Cotton Valley trend in East Texas. Forest expects to pay approximately $255 million for 110 Bcfe of proved reserves and production that averaged 13 MMcfe/d in January. Forest has approximately 300 identified drilling locations in the play with an average estimated ultimate recovery of 1.2 Bcfe to 1.3 Bcfe per location. The assets are focused in the Woodlawn, Blocker, Carthage and Oak Hill Fields. Accompanying the reserves and production, Forest also expects to acquire approximately 26,000 net acres in the fields, of which over 14,000 net acres are undeveloped. We expect this acquisition will provide another core area of growth to the company's Southern Business Unit following the offshore spin-off and will add 4 Bcfe and 8 Bcfe of additional production in 2006 and 2007, respectively.



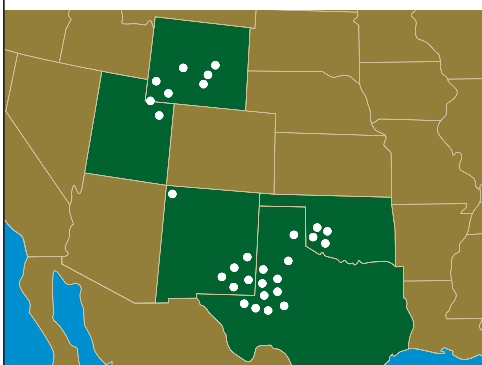
TARGETED ACQUISTION PROGRAM

ACQUISITION	PURCHASE PRICE ($MM)*	INITIAL PRODUCTION (MMCFE/D)	RESERVES (BCFE)	$ AMOUNT PER MCFE / RES.	NET ACREAGE	NET UNDEVELOPED ACREAGE
UNOCAL	224.0	66	138	1.62	252,000	93,000
NEW PERMIAN	112.9	25	109	1.04	32,000	5,000
WISER OIL	330.0	64	191	1.73	388,000	288,000
BUFFALO WALLOW	235.0	25	120	1.96	33,000	11,000
COTTON VALLEY	255.0	13	110	2.32	26,000	14,000
OTHERS	129.1	27	123	1.05	100,000	45,000
TOTAL	1,286.0	220	791	1.63	831,000	456,000

Operational Fact Sheet

Western

	2005	2004	2003
NET PRODUCTION			
Gas (MMcfe/d)	58.7	46.5	41.6
Liquids (MBbls/d)	9.4	6.8	3.3
ESTIMATED PROVED RESERVES			
Gas (Bcf)	367.1	252.9	206.7
Liquids (MMBbls)	52.3	44.9	30.3
Equivalent (Bcfe)	680.9	522.8	389.3
DEVELOPED ACREAGE			
Gross	274,881	232,080	312,958
Net	157,556	131,602	98,636
UNDEVELOPED ACREAGE			
Gross	197,206	179,529	251,999
Net	97,678	100,091	114,926
GROSS WELL COUNT			
Gas	3,655	2,941	535
Oil	2,661	2,735	1,435
CAPITAL EXPENDITURES In thousands			
	$492,123	$258,352	$193,014



2005 HIGHLIGHTS

- 100% success rate with IP's at Buffalo Wallow averaging 3.6 MMcfe/d, significantly higher than original forecasts, due to improved technologies and deep pay completions
- Acquired a total of 33,000 + acres at Buffalo Wallow
- Began re-entry and drilling program in the Fusselman/Atoka and Morrow sands in the Greater Haley/Vermejo Area. Combined production in the area in excess of 18 MMcfe/d in December 2005, a 29% increase since July 2005.
- Added approximately 5,900 acres in the Greater Haley/Vermejo Area bringing the total to 36,000 net acres
- Total of 24 wells drilled with a 100% success rate in the Central Midland Basin with 85 potential locations identified
- Acquired 8 drilling rigs to work on Forest-owned properties

FUTURE STRATEGY

- 2006 drilling program calls for over 200 new wells and a continued high pace of additional capital projects
- Plan to drill approximately 59 wells at Buffalo Wallow with plans to add a 5th and 6th rig to the program during 2006
- Active drilling program planned in the Greater Haley/Vermejo Area with 3 drilling wells, and a 2 rig active re-entry program
- Continued step-out and high exploitation and development activity in the Central Midland Basin
- Addition of a ninth rig in mid-2006
- Technology will continue to play a major role in the exploitation of existing, under-exploited assets throughout the region

Canada

	2005	2004	2003
NET PRODUCTION			
Gas (MMcfe/d)	51.8	43.6	34.5
Liquids (MBbls/d)	3.4	3.5	2.8
ESTIMATED PROVED RESERVES			
Gas (Bcf)	141.5	117.5	117.9
Liquids (MMBbls)	5.0	5.8	7.3
Equivalent (Bcfe)	171.5	152.1	161.6
DEVELOPED ACREAGE			
Gross	236,678	185,369	209,189
Net	136,837	103,964	102,887
UNDEVELOPED ACREAGE			
Gross	1,118,462	1,378,226	1,419,937
Net	598,481	826,340	794,722
GROSS WELL COUNT			
Gas	515	471	231
Oil	323	316	346
CAPITAL EXPENDITURES In thousands			
	$115,019	$158,310	$46,518

2005 HIGHLIGHTS

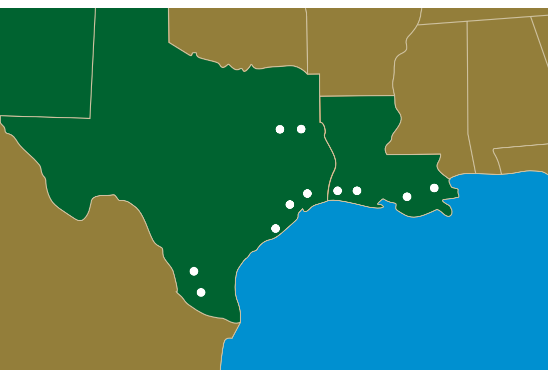
- Continued with exploitation strategy in the Wild River, Evi/Slave Point and Hayter Areas and managed exploration strategy in the Foothills in Alberta, including Palliser, Copton, Narraway and Waterton areas
- Overall Business Unit exit rate production increase of 26% from 2004 to 81 MMcfe/d in December 2005
- Wild River realized production gains of 278% as the field increased net production from a first quarter 2005 exit rate of 9 MMcfe/d to a 2005 exit rate of 25 MMcfe/d
- Drilled 4 wells in the Alberta Foothills with 100% success

FUTURE STRATEGY

- 2006 drilling program calls for 75 new wells and a continued high pace of additional capital projects
- Approximately 100 down-spacing locations identified on 29,000 acres at Wild River with 160 acre down-spacing and commingling approved, with plans to drill approximately 40 wells in 2006
- Evi/Slave Point play has approximately 50 potential development locations with reserve potential between 75 and 130 MBbls per well on 10,500 gross acres and 12 wells to be drilled in 2006
- Approximately 45,000 gross acres at Narraway and Palliser in the Alberta Foothills with 3-5 major Cretaceous structures identified and deep sour gas potential
- Completing Waterton horizontal well in Southern Foothills
- Evaluate opportunities related to our extensive Mackenzie Valley/Delta acreage and our unbooked reserves

Southern

	2005	2004	2003
NET PRODUCTION			
Gas (MMcfe/d)	27.7	34.7	28.5
Liquids (MBbls/d)	2.7	3.2	2.4
ESTIMATED PROVED RESERVES			
Gas (Bcf)	125.2	140.2	167.9
Liquids (MMBbls)	10.1	9.6	11.3
Equivalent (Bcfe)	185.8	197.6	235.7
DEVELOPED ACREAGE			
Gross	101,554	94,415	123,236
Net	59,118	57,272	66,978
UNDEVELOPED ACREAGE			
Gross	259,310	208,688	60,100
Net	122,583	90,093	38,490
GROSS WELL COUNT			
Gas	344	322	196
Oil	165	129	132
CAPITAL EXPENDITURES In thousands			
	$39,645	$70,392	$129,172



2005 HIGHLIGHTS

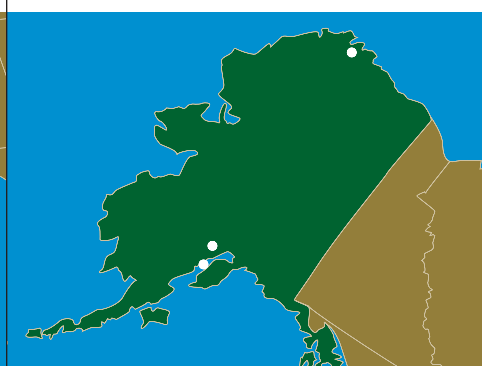
- Took over drilling operations at the Katy Field with numerous infill drilling opportunities
- Successfully implemented workover program at West White Lake adding 7 MMcfe/d

FUTURE STRATEGY

- 2006 onshore strategic program includes drilling approximately 45 new wells
- Exploitation efforts on the Cotton Valley assets to be acquired in East Texas, including 20 wells in 2006 and 50 wells in 2007
- 10 wells identified for 2006 in the Katy Field
- Evaluating deep objectives at West White Lake on 6,600 acres with seismic coverage
- Plan to shoot 132 square miles of new proprietary 3-D seismic at Sabine. Total gross acreage in the play is approximately 157,000 acres.

Alaska

	2005	2004	2003
NET PRODUCTION			
Gas (MMcfe/d)	6.4	–	–
Liquids (MBbls/d)	5.8	7.3	9.5
ESTIMATED PROVED RESERVES			
Gas (Bcf)	19.7	16.8	10.3
Liquids (MMBbls)	17.2	16.8	20.2
Equivalent (Bcfe)	122.8	117.5	131.4
DEVELOPED ACREAGE			
Gross	308,284	301,990	305,030
Net	34,029	31,124	37,379
UNDEVELOPED ACREAGE			
Gross	1,425,943	1,380,538	1,438,220
Net	1,196,061	1,150,656	1,208,798
GROSS WELL COUNT			
Gas	4	3	1
Oil	1,644	1,644	921
CAPITAL EXPENDITURES In thousands			
	$20,437	$21,928	$68,933



2005 HIGHLIGHTS

- Increased onshore Cook Inlet production from zero to 11 MMcfe/d in December 2005
- New gas supply contract commenced in the fourth quarter of 2005
- Net undeveloped acreage in the Cook Inlet of approximately 101,000 acres near discoveries, adding 18,500 acres in 2005
- Total undeveloped acreage of almost 1.2 million acres in Alaska

FUTURE STRATEGY

- 2006 drilling program calls for new gas exploration wells around the Cook Inlet
- Continued focus on lease acquisition as an integral part of the successful exploration program
- Continued emphasis on gas exploration onshore to support an increase in demand for gas by the local markets

International and Other Assets

	2005	2004	2003
ITALY: UNDEVELOPED ACREAGE			
Gross	756,857	756,857	940,926
Net	755,975	756,857	743,230
WEST AFRICA: UNDEVELOPED ACREAGE			
Gross	5,180,971	7,184,101	11,395,722
Net	2,438,252	3,890,776	7,576,923
CAPITAL EXPENDITURES In thousands			
	$3,688	$5,755	$8,211

INTERNATIONAL 2005 HIGHLIGHTS

- Initiated a gas marketing program in South Africa to identify customers for the Ibhubesi Field
- Obtained farm-out agreement of Gabon prospect with a full carry

INTERNATIONAL FUTURE STRATEGY

- Continue to work to obtain gas purchase and pipeline contracts in South Africa
- Drill an exploration test in Gabon in 2006 in an offset area to an existing discovery on a carried interest
- Shoot 3-D seismic on a carry on the northern portion of our 2.4 million acre block in Gabon
- Plan to drill our first shallow test exploratory well at Monte Pallano in Central Italy

OTHER ASSETS

- 8 company-owned drilling rigs (9th rig available in mid-2006)
- 5.4 million net undeveloped acres
- Unbooked reserves at MacKenzie Delta
- South Africa production tested at 220 MMcfe/d
- $506 million net operating loss carry-forwards and $198 million of tax pools in Canada
- 40% ownership in Cook Inlet Pipeline Company

Executive Officers

H. CRAIG CLARK, 49
President and Chief Executive Officer
Years of Service: 5

DAVID H. KEYTE, 49
Executive Vice President and
Chief Financial Officer
Years of Service: 18

CECIL N. COLWELL, 55
Senior Vice President –
Worldwide Drilling
Years of Service: 17

LEONARD C. GURULE, 49
Senior Vice President – Alaska
Years of Service: 3

J.C. RIDENS, 50
Senior Vice President – Southern U.S.
Years of Service: 2

R. SCOT WOODALL, 44
Senior Vice President – Western U.S.
Years of Service: 6

MATTHEW A. WURTZBACHER, 43
Senior Vice President –
Corporate Planning and Development
Years of Service: 7

CYRUS "SKIP" D. MARTER IV, 42
Vice President, General Counsel
and Secretary
Years of Service: 4

VICTOR A. WIND, 32
Corporate Controller
Years of Service: 1

Board of Directors

WILLIAM L. BRITTON*, age 71, has been a director since 1996. Mr. Britton is a consultant with the law firm of Bennett Jones LLP. He served as a partner of Bennett Jones LLP from 1962 until December 2004, and was Managing Partner and Chairman from 1981 to 1997. Mr. Britton is Vice Chairman and Lead Director of ATCO Ltd. and Canadian Utilities Limited and Deputy Chairman of Akita Drilling Ltd. He is a director of ATCO Gas and Pipeline Ltd., Barking Power Limited, Thames Power Limited, Hanzell Vineyards, Limited, and The Denver Broncos Football Club. He is a member of our Nominating and Corporate Governance Committee.

H. CRAIG CLARK, age 49, has served as our President and Chief Executive Officer, and as a director of Forest since July 2003. Mr. Clark joined Forest in September 2001 and served as President and Chief Operating Officer through July 2003. Mr. Clark was employed by Apache Corporation, an oil and gas exploration and production company, from 1989 to 2001, where he served in various management positions, including Executive Vice President – U.S. Operations and Chairman and Chief Executive Officer of Pro-Energy, an affiliate of Apache. Mr. Clark is a member of our Executive Committee.

CORTLANDT S. DIETLER*, age 84, has been a director since 1996. Mr. Dietler has served as Chairman of the Board of TransMontaigne Inc., an independent provider of supply chain management for fuel, since April 1995 and served as Chief Executive Officer from 1995 to 1999. Mr. Dietler is a director of Hallador Petroleum Company, an oil and gas exploration and production company. Mr. Dietler is also a director of Cimarex Energy Co., an oil and gas exploration and production company. He is the Chairman of our Nominating and Corporate Governance Committee and is a member of our Compensation Committee.

DOD A. FRASER*, age 55, has been a director since 2000. Mr. Fraser is President of Sackett Partners Incorporated, a consulting company, and member of corporate boards, since 2000. Previously, Mr. Fraser was an investment banker; a General Partner of Lazard Freres & Co. and most recently a Managing Director and Group Executive of Chase Manhattan Bank, now JP Morgan Chase, where he led the global oil and gas group. Mr. Fraser is a board member of Smith International, Inc., an oilfield service company, and Terra Industries, Inc., a nitrogen-based fertilizer company. Mr. Fraser serves as Chairman of our Audit Committee and is a member of our Nominating and Corporate Governance Committee.

FORREST E. HOGLUND*, age 72, has been a director since 2000. Mr. Hoglund has served as our non-executive Chairman of the Board since September 2003. Mr. Hoglund has served as Chairman and Chief Executive Officer of SeaOne Maratime Corp., a natural gas transportation company, since December 2004. Mr. Hoglund has served as Chairman and Chief Executive Officer of Artic Resources Company, Ltd., a natural gas pipeline company, since 2000. He served as Chairman of the Board of EOG Resources, Inc. from 1987 to 1999 and President from 1990 to 1996. Mr. Hoglund serves as Chairman of our Executive Committee and is a member of our Compensation Committee.

JAMES H. LEE*, age 57, has been a director since 1991. Mr. Lee has served as the Managing General Partner of Lee, Hite & Wisda Ltd., an oil and gas consulting firm, since 1984. Mr. Lee is a director of Frontier Oil Corporation, a crude oil refining and wholesale marketing company. He is a member of our Audit Committee and Executive Committee.

JAMES D. LIGHTNER*, age 53, became a director in 2004. Mr. Lightner is a Partner and Chief Executive Officer of Orion Energy Partners, an oil and gas exploration and production company. From 1999 to 2004, Mr. Lightner served in various capacities with Tom Brown, Inc., an oil and gas exploration and production company, including Director, Chairman, Chief Executive Officer and President. Prior to 1999, he served as Vice President and General Manager of EOG Resources, Inc. Mr. Lightner is a director of W.H. Energy Services Inc., an oil field services company. He is the Chairman of our Compensation Committee.

PATRICK R. MCDONALD*, age 48, became a director in 2004. Mr. McDonald has served as Chief Executive Officer, President and Director of Nytis Exploration Company, an oil and gas exploration company, since April 2003. From 1998 to 2003, Mr. McDonald served as President, Chief Executive Officer and Director of Carbon Energy Corporation, an oil and gas exploration and production company. From 1987 to 1997, he served as Chairman, Chief Executive Officer and President of a company that he founded, Interenergy Corporation, a natural gas gathering, processing and marketing company. Mr. McDonald is a member of our Audit Committee.

* *Notes Independent Director. Our Board of Directors uses the independence standards adopted by the Securities and Exchange Commission and the New York Stock Exchange in making determinations of director independence.*

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2005

or

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

For the transition period from to

Commission File Number: 1-13515

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

State of incorporation: **New York** I.R.S. Employer Identification No. **25-0484900**

707 17th Street - Suite 3600 - Denver, Colorado **80202**
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code: **303-812-1400**

Securities registered pursuant to Section 12(b) of the Act:

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 ☒ No ☐

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. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer' in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

The aggregate market value of the voting stock held by non-affiliates of the registrant as of June 30, 2005, the last business day of the registrant's most recently completed second fiscal quarter, was $2,263,162,902 (based on the closing price of such stock on the New York Stock Exchange Composite Tape).

There were 62,756,723 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 28, 2006.

Document incorporated by reference: Portions of the registrant's notice of annual meeting of shareholders and proxy statement to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end of December 31, 2005 are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

Item 1. Business.

General

Forest is an independent oil and gas company engaged in the acquisition, exploration, development, and production of natural gas and liquids primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Throughout this Form 10-K we use the terms "Forest," "Company," "we," "our," and "us" to refer to Forest Oil Corporation and its subsidiaries.

We conduct our operations in five business units: the Western United States ("Western"), Southern United States ("Southern") (formerly the Gulf Coast business unit), Canada, Alaska, and International. We conduct exploration and development activities in each of our North American core areas and in our International locations; however, all of our estimated proved reserves and producing properties are located in North America. While discoveries of oil and gas have been made in our International business unit, no proven reserves have been recorded to date. At December 31, 2005, approximately 88% of our estimated proved oil and gas reserves were in the United States and approximately 12% were in Canada.

In the following discussion, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. See "Forward-Looking Statements," below, for more details. We also use a number of terms used in the oil and gas industry. See the heading "Glossary of Oil and Gas Terms," below, for the definition of certain terms.

Spin-off of Offshore Gulf of Mexico Operations

On March 2, 2006, Forest completed the spin-off of its offshore Gulf of Mexico operations by means of a special stock dividend, which consisted of a pro rata spin-off (the "Spin-off") of all outstanding shares of Forest Energy Resources, Inc. ("FERI"), a total of 50,637,010 shares of common stock, to holders of record of Forest common stock as of the close of business on February 21, 2006. Immediately following the Spin-off, FERI was merged with a subsidiary of Mariner Energy, Inc. ("Mariner") in a stock for stock transaction (the "Merger"). Mariner commenced trading on the New York Stock Exchange on March 3, 2006. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," for further details.

As a result of the Spin-off, Forest is now a company focused on longer-lived onshore resources with a significant drilling inventory and an acquisition track record.

Business Strategy

Our strategy includes four key elements: to conduct exploitation programs that provide organic growth, make strategic acquisitions, control costs, and remain financially flexible.

Conduct Exploitation Programs

The acquisitions of The Wiser Oil Company in 2004, and the Buffalo Wallow field in 2005, and the recent announcement to complete the acquisition of East Texas Cotton Valley assets on March 31, 2006 described below, provide us with assets conducive to low-risk, repeatable development and exploitation opportunities. In 2006, Forest expects organic growth from its planned exploitation activities, including exploration and development, workovers, stimulation treatments, water floods, and recompletions.

Make Strategic Acquisitions

We pursue strategic acquisitions that meet our criteria for investment returns and that are consistent with our operational focus. We believe this enables us to leverage our technical expertise and existing land and infrastructure positions. Since the inception of our four-point game plan in 2003, through 2005 we have spent approximately $1.2 billion (including deferred tax gross ups of $151 million and excluding goodwill recorded in connection with business combinations of approximately $87 million) to acquire approximately 700 Bcfe of estimated proved reserves. In general, our recent acquisition program has focused on acquisitions of properties that have substantial development drilling opportunities and undeveloped acreage.

Continue to Focus on Cost Control

Maintaining capital spending discipline and a focus on cost control are keystones of Forest's business philosophy. We establish budgets that generate discretionary cash flow in each of our producing business units. Another critical area of our cost control efforts is lease operating expenses. Although lease operating expenses increased in 2005 as compared to 2004, the primary driver for the increase on a unit-of-production basis was hurricane-related repairs and downtime in the Gulf of Mexico. Lease operating expenses on a per-unit of production basis would have likely been significantly lower if approximately 16 Bcfe of production had not been deferred as a result of the hurricanes.

Maintain Financial Flexibility

We seek to maintain financial flexibility and sufficient liquidity to capitalize on opportunities as they arise. We reduced our debt-to-book capitalization ratio from 44% at the end of 2003 to 38% at December 31, 2004, and to 34% at December 31, 2005. Generally, we attempt to maintain a debt-to-book capitalization ratio of between 30% and 40%. We had approximately $7 million of cash on hand and $439 million available under our credit facility at December 31, 2005. In addition, none of our outstanding long-term debt is due until after 2007, and 69% is not due until after 2008.

Hedging is an important part of our strategy to mitigate our exposure to commodity price volatility. We have a board-approved policy related to commodity hedging activities. As of March 3, 2006 we have hedged, via swaps and collar instruments, an estimated 38-40% of our estimated 2006 production. The majority of our current hedges were executed in order to support the economics of recent acquisitions.

Acquisitions

During 2005, we made approximately $314 million (including approximately $71 million of deferred tax gross up and excluding $23 million of goodwill recorded in connection with a business combination) of oil and gas property acquisitions. The largest acquisition was of oil and gas properties in the Buffalo Wallow area in the Texas Panhandle in April 2005. The Buffalo Wallow transaction included the payment of $197 million in cash and the assumption of $35 million of debt to acquire approximately 120 Bcfe of estimated proved reserves as well as approximately 33,000 gross acres primarily in Hemphill and Wheeler Counties, Texas. We have increased the production in the Buffalo Wallow area from 20 MMcfe per day to 34 MMcfe per day and have increased estimated proved reserves to approximately 167 Bcfe as of December 31, 2005 due to our continued development of the area throughout 2005.

During 2004, we made approximately $436 million (including $47 million of deferred tax gross up and excluding $64 million of goodwill, each recorded in connection with a business combination) of oil and gas asset acquisitions. Our largest acquisition in 2004 was of The Wiser Oil Company ("Wiser") in June 2004 which included oil and gas assets valued at $347 million. The Wiser transaction included the payment of $171 million in cash and the assumption of $163 million of debt to acquire approximately 186 Bcfe of estimated proved reserves, producing 64 MMcfe per day at the time the acquisition closed and approximately 388,000 total net acres. The Wiser acquisition enhanced the asset base of our Canadian and Western business units and increased estimated proved reserves and production in each of our Western, Canada, and Gulf Coast business units.

Pending Acquisition

In February of 2006, Forest announced its plans to acquire oil and gas properties located primarily in the Cotton Valley trend in East Texas. Forest agreed to pay approximately $255 million, subject to customary adjustments, for properties with an estimated 110 Bcfe of proved reserves and production that averaged 13 MMcfe per day in January 2006. Accompanying the reserves and production, Forest also will gain approximately 26,000 net acres in the fields, of which approximately 14,000 net acres are undeveloped. The transaction is expected to close on March 31, 2006 and is subject to customary closing conditions. Forest expects that the acquisition of these properties will provide another core area of growth and add significant onshore activity to the Southern business unit.

Property Sales

As a part of our ongoing program to upgrade the quality of our portfolio, we dispose of non-strategic assets. Assets located outside our focus areas or those with marginal value, high operating costs, or high abandonment liabilities are identified for sale or trade. During 2005, we sold assets, including oil and gas properties with estimated proved reserves of approximately 15 Bcfe, for total cash proceeds of approximately $24 million. During 2004, we disposed of assets, including oil and gas properties with estimated proved reserves of approximately 85 Bcfe, for total cash proceeds of approximately $106 million. These sales included offshore platforms with near-term abandonment obligations.

Hurricane Impact

During 2005, our Gulf of Mexico operations were adversely affected by one of the most active hurricane seasons in recorded history. As of December 31, 2005, Forest had approximately 70 MMcfe per day of net production shut-in relating to Forest's offshore Gulf of Mexico operations. Forest estimates that total production deferred from hurricanes Katrina and Rita in the third and fourth quarters of 2005 was approximately 16 Bcfe.

As a result of the completion of the Spin-off as discussed above, the residual effects of the 2005 hurricanes have been largely eliminated. We expect that the risks associated with future hurricane activity will be largely diminished, although production interruptions may still occur to the extent third party transportation and processing facilities are damaged or if our onshore properties suffer damage.

Business Unit Exploration and Production Activities

At December 31, 2005, we held interests in approximately 3,900 net oil and gas wells in the United States and Canada and sold 165.2 Bcfe of oil and gas, or an average of 453 MMcfe per day during 2005. Approximately 84% of our total production was in the United States, and 16% was in Canada.

The production volumes and estimated proved reserves for our business units in the United States and Canada as of and for the period ending December 31, 2005 are summarized below.

	Production				Reserves
Business Unit	**Natural Gas (MMcf)**	**Oil & NGLs (MBbls)**	**Total (MMcfe)**	**Average Daily (MMcfe)**	**Total (Bcfe)**
Gulf Coast:[1]					
Offshore	49,120	2,783	65,818	180.3	306.1
Southern	10,125	986	16,041	43.9	185.8
Western[2]	21,314	3,447	41,996	115.1	680.8
Alaska[3]	2,353	2,100	14,953	41.0	122.9
Canada[4]	18,921	1,252	26,433	72.4	171.5
Total	101,833	10,568	165,241	452.7	1,467.1

(1) Gulf Coast production and estimated proved reserves are located in South Texas, Louisiana Gulf Coast, and offshore Gulf of Mexico. The offshore component of the business unit represents the properties that were included in the Spin-off, which was completed on March 2, 2006 as discussed above.

(2) Western production and estimated proved reserves are located in Western Oklahoma, Utah, Wyoming, West Texas, Texas Panhandle, and New Mexico.

(3) Alaska production and estimated proved reserves are primarily located onshore and offshore Cook Inlet.

(4) Canada production and estimated proved reserves are primarily located in Alberta and British Columbia.

The following table shows expenditures for exploration and development and property acquisitions, for each of our business units during 2005.

Business Unit	**Exploration and Development**	**Property Acquisitions**	**Total**
	(In Thousands)		
Gulf Coast:			
Offshore[1]	$166,436	—	166,436
Southern	39,157	488	39,645
Western	187,399	304,724	492,123
Alaska	20,437	—	20,437
Canada	107,421	7,598	115,019
International	3,688	—	3,688
Total[3]	$524,538	312,810[2]	837,348

(1) The offshore component of the business unit represents the properties that were included in the Spin-off, which was completed on March 2, 2006 as discussed above.

(2) Includes approximately $71 million of deferred tax gross up and excludes approximately $23 million of goodwill recorded in connection with a business combination.

(3) Does not include estimated discounted asset retirement obligations of $16.3 million, including $.7 million assumed in connection with acquisition activities.

Gulf Coast/Southern

The Gulf Coast business unit had a production decrease of 19% on a Mcfe basis in 2005 compared to 2004. The decrease in production was due primarily to shut-in production due to hurricanes Katrina and Rita. After the Spin-off, which included all of Forest's offshore Gulf of Mexico operations, this business unit was renamed the Southern business unit. The Southern business unit's major capital expenditures in 2006 are expected to be for development drilling in South Texas and in the East Texas Cotton Valley play, subject to the closing of the pending Cotton Valley acquisition scheduled for late-March 2006.

Western

The Western business unit had a production increase of 32% in 2005 compared to 2004. Production was increased through a combination of acquisitions and exploitation, as well as an increased drilling program that totaled 314 gross wells. The Buffalo Wallow area has been the primary focus of the business unit, with average production increasing from 20 MMcfe per day at the time of acquisition to a current rate of 34 MMcfe per day. In 2006, capital expenditures in this business unit will be focused in four areas: Buffalo Wallow, waterflooding and development drilling in the central Permian Basin, deep gas drilling in the Greater Haley area of West Texas, and exploratory and development drilling in the Rocky Mountains.

Canada

The Canada business unit had a production increase of 12% in 2005 compared to 2004 despite the sale of 17% of its production in December 2004. Production was increased through development drilling activities and exploratory drilling success in the Foothills and Wild River areas in Central Alberta. In 2006, capital expenditures in this business unit will be focused primarily in the Wild River, Evi/Loon, and Foothills areas.

Alaska

The Alaska business unit had a production decrease of 7% in 2005 compared to 2004. Production decreased due to natural declines in the offshore oil fields offset in part by increased natural gas production in 2005 at West Foreland and Three Mile Creek. In 2006, capital expenditures in this business unit are forecasted to increase as more projects are funded relating to the onshore Cook Inlet natural gas exploration program.

International

The International business unit was able to reduce its work commitments in 2005 and high-grade its portfolio to focus primarily on South Africa, Gabon, and Italy. Partners had been previously obtained for exploration activities in both Gabon and South Africa, which reduced the need for Forest's capital to be invested in these areas. In 2006, the business unit's activity will be focused on securing gas contracts in South Africa, drilling a shallow oil prospect in Gabon with a carry by our partners of the costs up to $6 million on the first well, and drilling a gas test in central Italy.

Reserves

The following table shows our estimated quantities of proved reserves as of December 31, 2005 and 2004. All estimated proved reserves are currently located in North America. See Note 14 to the Consolidated Financial Statements for additional information regarding estimated proved reserves.

	December 31,			
	2005			2004
	Spin-off Properties(1)	Retained Properties	Total	Total
Proved developed:				
Natural gas (MMcf)	142,143	497,213	639,356	627,130
Liquids (MBbls)	8,792	62,805	71,597	67,045
Total (MMcfe)	194,895	874,043	1,068,938	1,029,400
Proved undeveloped:				
Natural gas (MMcf)	88,999	156,328	245,327	173,995
Liquids (MBbls)	3,702	21,771	25,473	21,768
Total (MMcfe)	111,211	286,954	398,165	304,603
Total proved:				
Natural gas (MMcf)	231,142	653,541	884,683	801,125
Liquids (MBbls)	12,494	84,576	97,070	88,813
Total (MMcfe)	306,106	1,160,997	1,467,103	1,334,003

(1) These estimated proved reserves relate to Forest's offshore Gulf of Mexico properties, which were included in the Spin-off as discussed above.

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

Forest annually files estimates of its oil and gas reserves with the U.S. Department of Energy ("DOE"). During 2005, we filed estimates of our oil and gas reserves as of December 31, 2004 with the DOE, which were consistent with the reserve data reported for the year ended December 31, 2004 in Note 14 to the Consolidated Financial Statements.

Independent Audit of Reserves

For financial reporting purposes, including this Form 10-K, Forest uses reserve estimates prepared by its internal staff of engineers. A substantial portion of our reserves are audited by independent petroleum engineers engaged by Forest. Our reserve audit procedures require the independent reserve engineers to prepare their own independent estimates of proved reserves for fields comprising at least 80% of Forest's year-end SEC PV10% value for each country in which Forest owns fields for which proved reserves have been recorded. The fields selected each year comprise at least the top 80% of Forest's fields based on the SEC PV10% value of such fields and a minimum of 80% of the SEC PV10% value of the fields added during the year through discoveries, extensions, and acquisitions. Forest may also include fields that fall outside of the top 80% of the SEC PV10% value that represent material volumes of proved reserves, have experienced material revisions to prior estimates of proved reserve volumes or value, or have experienced changes as a result of new operational activity. The procedures prohibit exclusions of any fields, or any part of a field, that comprises part of the top 80% of the SEC PV10% value. The independent reserve engineers then compare their estimates to those prepared by Forest. The independent reserve audits prepared for Forest are not financial audits and are not performed in accordance with the established generally accepted financial audit procedures. Instead, a reserve audit is conducted based on rules and regulations, reserve definitions and costs, and price parameters specified by the SEC.

For the year-end 2005, we engaged two independent petroleum engineering firms to perform reserve audit services. DeGolyer and MacNaughton audited the reserves attributable to Forest's properties located onshore in North America and offshore in the Cook Inlet, Alaska, and Ryder Scott Company audited our estimates of the reserves attributable to our properties located offshore in the Gulf of Mexico. Together, these firms independently audited estimates relating to properties constituting approximately 86% of our reserves, as of December 31, 2005, based on the reserve volumes. When compared on a field-by-field basis, some of Forest's estimates of net proved reserves are greater and some are less than the estimates prepared by Forest's independent petroleum engineers. However, there was no material difference, in the aggregate, between Forest's internal estimates of total net proved reserves and the estimates prepared by the independent petroleum engineers.

Drilling Activities

During 2005, we drilled a total of 415 gross wells, 23 of which were injection wells. Of the remaining 392 wells, 141 were classified as exploration and 251 were classified as development. Our 2005 drilling program achieved a 97% success rate. The following table summarizes the number of wells drilled during 2005, 2004, and 2003, excluding any wells drilled under farmout agreements, royalty interest ownership, or any other wells in which we do not have a working interest. As of December 31, 2005, we had 25 gross (17 net) wells in progress in the United States and 9 gross (5 net) wells in progress in Canada.

	Year Ended December 31,					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Gas wells	232	32	58	25	54	29
Oil wells	16	14	34	31	17	7
Non-productive[1]	3	3	6	5	10	6
Total	251	49	98	61	81	42
Exploratory wells, completed as:						
Gas wells	100	51	36	20	11	8
Oil wells	31	27	1	1	3	2
Non-productive[1]	10	5	9	5	9	7
Total	141	83	46	26	23	17

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

Productive Wells

The following table summarizes our productive wells as of December 31, 2005, all of which are located in the United States and Canada:

	United States				Canada				Total	
	Operated Wells		Non-operated Wells[(1)]		Operated Wells		Non-operated Wells		Operated and Non-Operated Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gas	938	759	3,797	501	321	259	194	49	5,250	1,568
Oil	2,164	1,883	2,653	253	229	205	94	20	5,140	2,361
Total	3,102	2,642	6,450	754	550	464	288	69	10,390	3,929

(1) The large variance between gross and net non-operated wells is primarily a result of our ownership interest in approximately 2,931 gross gas wells in the San Juan Basin with an average working interest of approximately 1% and our ownership interest in approximately 1,510 gross oil wells in the Prudhoe Bay area with an average working interest of approximately .02%.

Acreage

The following table summarizes developed and undeveloped acreage in which we owned a working interest as of December 31, 2005 and 2004. A majority of our developed acreage in the United States and Canada is subject to mortgage liens securing our bank credit facilities. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this summary, as well as acreage related to any options held by us to acquire additional leasehold interests.

	December 31,							
	2005				2004			
	Developed Acreage		Undeveloped Acreage		Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States:								
Gulf Coast:								
Offshore	883,340	364,509	335,992	219,446	917,968	407,854	388,056	255,994
Southern	101,554	59,118	259,310	122,583	94,415	57,272	208,688	90,093
Western	274,881	157,556	197,206	97,678	232,080	131,602	179,529	100,091
Alaska	308,284	34,029	1,425,943	1,196,061	301,990	31,124	1,380,538	1,150,656
	1,568,059	615,212	2,218,451	1,635,768	1,546,453	627,852	2,156,811	1,596,834
Canada	236,678	136,837	1,118,462	598,481	185,369	103,964	1,378,226	826,340
International:								
South Africa	—	—	2,771,695	1,474,542	—	—	4,774,825	2,927,066
Gabon	—	—	2,409,276	963,710	—	—	2,409,276	963,710
Italy	—	—	756,857	755,975	—	—	756,857	756,857
Romania	—	—	—	—	—	—	1,073,693	536,846
	—	—	5,937,828	3,194,227	—	—	9,014,651	5,184,479
Total	1,804,737	752,049	9,274,741	5,428,476	1,731,822	731,816	12,549,688	7,607,653

At December 31, 2005, approximately 16% and 11% of our net undeveloped acreage in the United States and Canada was held under leases that have terms that will expire in 2006 and 2007, respectively, if not extended by exploration or production activities. We anticipate that 101,962 acres will expire in 2006 in Italy when one of the blocks expires. Further exploration work is required to retain the remaining acreage in Italy as well as Gabon. The decreased net acreage shown for South Africa for 2005 was due to mandatory relinquishments as well as a farmout of a portion of one of our subleases to a partner. The South African national government recently adopted legislation to revise the process pursuant to which it grants petroleum exploration and production licenses. Under the new regulations, we have applied to the government to convert one existing prospecting sublease into an exploration right. In addition, we are in the process of applying for a production right covering the geographic area of our other existing prospecting sublease. Because the regulations implementing the new legislation in South Africa are not yet final, we cannot predict whether these applications, if granted, will meet our economic or operational requirements, in which event we may choose to relinquish our rights.

Production, Average Sales Prices, and Production Costs

The following table reflects production, sales price, and production cost information for the years ended December 31, 2005, 2004, and 2003.

	United States			Canada			Total Company		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
Natural Gas:									
Sales price received (per Mcf)	$ 7.53	6.10	5.27	6.70	4.23	3.09	7.37	5.82	4.98
Effects of energy swaps and collars (per Mcf)[1]	(1.24)	(.56)	(.52)	—	—	—	(1.01)	(.48)	(.45)
Average sales price (per Mcf)[1]	$ 6.29	5.54	4.75	6.70	4.23	3.09	6.36	5.34	4.53
Natural gas sales volumes (MMcf)	82,912	91,420	84,368	18,921	15,946	12,609	101,833	107,366	96,977
Liquids:									
Oil and Condensate:									
Sales price received (per Bbl)	$ 52.78	39.24	29.08	41.92	35.49	28.57	51.67	38.88	29.03
Effects of energy swaps and collars (per Bbl)[1]	(11.22)	(7.84)	(4.04)	—	—	—	(10.07)	(7.09)	(3.71)
Average sales price (per Bbl)[1]	$ 41.56	31.40	25.04	41.92	35.49	28.57	41.60	31.79	25.32
Natural gas liquids:									
Average sales price (per Bbl)	$ 29.61	26.05	18.58	36.15	28.08	20.88	30.76	26.56	19.62
Total liquids:									
Average sales price (per Bbl)[1]	$ 39.12	30.75	24.65	40.04	33.25	25.65	39.23	31.05	24.77
Liquids sales volumes (MBbls)	9,316	9,550	7,686	1,252	1,287	1,015	10,568	10,837	8,701
Average sales price (per Mcfe)[1]	**$ 6.38**	**5.38**	**4.52**	**6.69**	**4.66**	**3.47**	**6.43**	**5.28**	**4.39**
Total sales volumes (MMcfe)	**138,808**	**148,720**	**130,484**	**26,433**	**23,668**	**18,699**	**165,241**	**172,388**	**149,183**
Production costs (per Mcfe):									
Lease operating expenses	$ 1.30	1.15	.85	.71	.76	.74	1.21	1.10	.83
Production and property taxes	.29	.21	.15	.11	.05	.02	.26	.19	.13
Transportation costs	.10	.09	.07	.22	.13	.01	.12	.10	.07
Total production costs (per Mcfe)	**1.69**	**1.45**	**1.07**	**1.04**	**.94**	**.77**	**1.59**	**1.38**	**1.03**

(1) Commodity swaps and collars were transacted to hedge the price of spot market volumes against price fluctuations. Average sales prices have been adjusted to reflect effects of energy swaps and collars. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk," concerning our hedging activities.

Marketing and Delivery Commitments

Our oil and gas production is sold to various purchasers in accordance with our credit policies and procedures. The policies and procedures take into account the credit-worthiness of potential purchasers 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 our ability to sell our production because any individual spot purchaser could be readily replaced by another spot purchaser. No single purchaser accounted for 10% or more of our total revenue in 2005.

United States

In the United States, Forest's production of natural gas is generally sold in the areas where it is produced or at nearby "pooling points." Our natural gas production is typically sold on a month-to-month basis in the spot market referencing published indices. Our production of oil and natural gas liquids is typically sold under short-term contracts at prices based upon posted field prices and is typically sold at the wellhead. During 2005, Forest entered into a physical delivery contract to supply between 5 and 15 MMcf per day of natural gas production from its Alaska business unit at a fixed price through December 2006.

Canada

In Canada, our natural gas production is sold by our subsidiary, Canadian Forest Oil Ltd. ("Canadian Forest"), either through a joint venture with other producers (the "Canadian Netback Pool"), which is a long-term commitment, or under direct sales contracts or spot contracts. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk," below, for further details. Our Canadian liquids production is generally sold at the wellhead under short-term market based contracts at prices posted at Alberta pipeline processing hubs that are netted back to the field.

Competition

Forest encounters competition in all aspects of its business, including acquisition of properties and oil and gas leases, marketing oil and gas, obtaining services and labor, and securing drilling rigs and other equipment necessary for drilling and completion of wells. Our ability to increase reserves in the future will be dependent on our ability to generate successful prospects on our existing properties, execute on major development drilling programs, acquire new producing properties, and acquire additional leases and prospects for future development and exploration. Factors that affect our ability to acquire properties include, among others, availability of desirable acquisition targets, staff and resources to identify and evaluate properties, available funds, and internal standards for minimum projected return on investment. Higher recent commodity prices have increased the cost of properties available for acquisition and a large number of the companies that we compete with have substantially larger staffs and greater financial and operational resources. Because of the nature of our oil and gas assets and management's experience in exploiting our reserves and acquiring properties, management believes that we effectively compete in our markets.

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 subject to regulation by state and federal agencies. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have adopted laws regulating the exploration for and production of crude oil and natural gas, including laws requiring permits for the drilling of wells, imposing bonding requirements in order to drill or operate wells, and providing authority for regulation relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Certain of our operations are conducted on federal land pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed BLM regulations and orders (which are subject to change by the BLM). In addition to permits required from other agencies, lessees must obtain a permit from the BLM prior to the commencement of drilling, and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of Outer Continental Shelf ("OCS") wells, the valuation of production, and the removal of facilities. Under certain circumstances, the BLM or the Mineral Management Service ("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 August 2005, Congress enacted the Energy Policy Act of 2005 ("EP Act 2005"). Among other matters, EP Act 2005 amends the Natural Gas Act ("NGA") to make it unlawful for any entity, as defined in the EP Act 2005, including otherwise non-jurisdictional producers such as Forest, to use any deceptive of manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission ("FERC"), in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing the provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme, or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The EP Act 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The EP Act 2005 reflects a significant expansion of the FERC's enforcement authority. Forest does not anticipate it will be affected by the EP Act 2005 any differently than other producers of natural gas.

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

Canada

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

The provinces in which we operate have legislation and regulation which govern land tenure, royalties, production rates and taxes, and environmental protection and other matters under their respective jurisdictions. The royalty regime in the provinces in which we operate is a significant factor in the profitability of our production. Crown royalties are determined by government regulation and are typically calculated as a percentage of the value of production. The value of the production and the rate of royalties payable depends on prescribed reference prices, well productivity, geographical location, and the type or quality of the product produced, and any royalties payable on production from lands other than Crown lands are determined by negotiations between Forest and the other parties.

Environmental Regulation

As a lessee and operator of onshore and offshore oil and natural gas properties in the United States and Canada, we are subject to stringent federal, state, provincial, and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas industry operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper closure of wells and restoration of properties that are being abandoned. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of capital costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production operations or the disposal of oilfield generated substances.

We currently operate or lease, and have in the past operated or leased, a number of properties that for many years have been used for the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove or remediate previously disposed wastes or property contamination, or to perform remedial plugging or pit closure to prevent future contamination. We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards.

While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future.

We have established internal guidelines to be followed in order to comply with environmental laws and regulations in the United States, Canada, and other relevant international jurisdictions. We employ an environmental, health and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

For further information regarding certain environmental matters, see Part I, Item 3—"Legal Proceedings," below.

Employees

As of December 31, 2005, we had 506 employees. None of our employees are currently represented by a union for collective bargaining purposes. On March 2, 2006, Forest completed the Spin-off described above. Following the Spin-off, as of March 3, 2006, we had 383 employees.

Geographical Data

Forest operates in one industry segment. For information relating to our geographic operating segments, see Note 13 to the Consolidated Financial Statements of this Form 10-K.

Offices

Our principal office is located in leased space at 707 17th Street, Denver, Colorado 80202, telephone 303.812.1400. We also lease field offices and subsidiary offices, including office space in Anchorage, Alaska; Green River, Wyoming; Hobbs, New Mexico; Odessa and Canadian, Texas; Calgary, Alberta, Canada; and Cape Town, South Africa. We believe that our facilities are adequate for our current operations.

Title to Properties

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

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Form 10-K.

Bbl. Barrel (of oil or natural gas liquids).

Bcf. Billion cubic feet (of natural gas).

Bcfe. Billion cubic feet equivalent.

Bbtu. One billion British Thermal Units.

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

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

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

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

Exploratory well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

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

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

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

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

MBbls. Thousands of barrels.

Mcf. Thousand cubic feet (of natural gas).

Mcfe. Thousand cubic feet equivalent.

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

MMcf. Million cubic feet.

MMcfe. Million cubic feet equivalent.

NGL. Natural gas liquids.

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

NYMEX. New York Mercantile Exchange.

Present value or PV10% or "SEC PV10%." When used with respect to oil and gas reserves, present value or PV-10 or SEC PV10% means the estimated future gross revenue to be generated from the production of net proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service, accretion, and future income tax expense or to depreciation, depletion, and amortization, discounted using monthly end-of-period discounting at a nominal discount rate of 10% per annum.

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

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

Proved reserves. Estimated quantities of crude oil, natural gas, and natural gas liquids which, upon analysis of geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions.

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

Undeveloped Acreage. Acreage 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 estimated proved reserves.

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

Available Information

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

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

In June 2005, we submitted to the New York Stock Exchange ("NYSE") the certification of the Chief Executive Officer of Forest required by Section 303A.12 of the NYSE Listed Company Manual, relating to Forest's compliance with the NYSE's corporate governance listing standards with no qualifications. Also, we included the certifications of the Chief Executive Officer and Chief Financial Officer of Forest required by Section 302 of the Sarbanes-Oxley Act of 2002 and related rules, relating to the quality of Forest's public disclosure, in this Form 10-K as Exhibits 31.1 and 31.2.

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 our current expectations and assumptions about future events and are 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 described under the heading “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;
- the amount, nature and timing of capital expenditures, including future development costs, 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, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, and sale of oil and gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment 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, cash flow and access to capital, the timing of development expenditures, and the other risks described 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 significantly 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, expressed 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 1A. Risk Factors.

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

Oil and 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 writedowns 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. Oil and gas prices are currently at or near historical highs and may fluctuate and decline significantly in the near future. 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, Russia, and South America; the domestic and foreign supply of oil and natural gas; the price and quantity of oil and gas imports; or general economic conditions.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 60% of our estimated proved reserves as of December 31, 2005 were natural gas reserves, our financial results in 2006 are more sensitive to movements in natural gas prices. Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. This may have a material adverse effect on our financial condition and results of operations.

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, cash provided by operating activities, and the issuance of debt and equity securities when market conditions permit. We also continue to examine alternative sources of long-term capital such as 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 non-recourse 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, the value and performance of Forest, and the credit ratings assigned to Forest by independent ratings agencies. We may be unable to execute our operating strategy if we cannot obtain adequate capital.

Availability under our bank credit facilities is based on a global borrowing base that is redetermined semi-annually, and may be redetermined at other times during a year at the option of the Company or the lenders. The global borrowing base may be reduced if oil and gas prices decline or we have downward revisions in our estimate of proved reserves. 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 credit agreements and indentures governing our debt securities, our ability to fund our planned capital expenditures could be adversely affected. After utilizing our available sources of financing, we could be forced to issue additional debt or equity securities to fund such expenditures. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet our capital requirements.

A curtailment of capital spending could adversely affect our ability to replace production and our future cash flow from operations and could result in a decline in our oil and gas reserves and production.

Estimates of oil and gas reserves are uncertain and inherently imprecise. Estimating our proved reserves involves many uncertainties, including factors beyond our control. The estimates of proved reserves and related future net revenues described in this Form 10-K are based on various assumptions, which may ultimately prove inaccurate. Petroleum engineers consider many factors and make assumptions in estimating oil and gas reserves and future net cash flows. Lower oil and gas prices generally cause lower estimates of proved reserves. Ultimately, actual production, revenues, and expenditures relating to our reserves will vary from our estimates, and these variations may be material. Also, we may revise estimates of proved reserves to reflect production history, results of exploration and development, and other factors, many of which are beyond our control. See Note 14, items (D) and (F), to the Consolidated Financial Statements, below, for further discussion of a downward revision of our reserves in 2003. As a result of lower oil and gas "spot" prices in the future or downward future reserve revisions, we could incur writedowns of our United States and Canadian full cost pools under "ceiling test" limitations pursuant to full cost accounting. If we were to record writedowns, shareholders' equity could be reduced significantly.

In estimating future net revenues from proved reserves, future prices and costs are assumed to be fixed and a fixed discount factor is applied. Our revenues, profitability, and cash flow could be materially less than our estimates if these assumptions and discount factor are incorrect. The present value of future net revenues from our proved reserves is not necessarily the actual current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on fixed prices and costs as of the date of the estimate. Actual future prices and costs fluctuate over time and may differ materially from those used in the SEC net present value estimate. The timing and amount of development expenditures and the rate and timing of oil, natural gas, and natural gas liquids production will affect both the timing of future net cash flows from proved reserves and their present value. In addition, the 10% discount factor that we use to calculate the net present value of future net cash flows for reporting purposes in accordance with the SEC's rules may not necessarily be the most appropriate discount factor. As a result, net present value estimates using actual prices and costs may be significantly less than the SEC estimate that is provided in this Form 10-K.

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%. 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.” Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test writedown would not impact cash flow from operating activities, but it 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, or if estimated future development costs increase. We cannot assure you that we will not experience ceiling test writedowns in the future. Our Canadian full cost pool, in particular, could be adversely impacted by moderate declines in commodity prices.

Leverage will materially affect our operations. As of December 31, 2005, the principal amount of our long-term debt was approximately $854 million, including approximately $154 million outstanding under our global bank credit facilities. On March 2, 2006, we used cash received from the Spin-off transaction of approximately $176 million to pay off the amount of borrowings under our U.S. credit facility. Our long-term debt represented 34% of our total capitalization at December 31, 2005. Further, we may incur additional debt in the future, including in connection with acquisitions and refinancings.

The level of our debt could have several important effects on our future operations, including, among others:

- a significant portion of our cash flow from operations will be applied to the payment of principal and interest on the debt and will not be available for other purposes;
- credit rating agencies have changed, and may continue to change, their ratings of our debt and other obligations as a result of changes in our debt level, financial condition, earnings, and cash flow; such ratings changes would in turn impact the costs, terms, conditions, and availability of financing;
- covenants contained in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate, and other purposes may be limited or burdened by increased costs or more restrictive covenants;
- we may be at a competitive disadvantage to similar companies that have less debt; and
- our vulnerability to adverse economic and industry conditions may increase.

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, 2005, our estimated discounted asset retirement obligation liability recorded in the balance sheet was approximately $211.6 million (including approximately $148 million related to those properties that were part of the Spin-off transaction completed on March 2, 2006), primarily for properties in offshore Gulf of Mexico and the Cook Inlet of Alaska. Approximately $32.7 million of abandonment costs were settled in 2005 and $33.3 million of abandonment costs are anticipated to be settled in 2006 (including $29.9 million related to those properties that were part of the Spin-off transaction completed on March 2, 2006), 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. Our reserves will decline as they are produced unless we are successful in our exploration and development activities or acquire new producing properties. 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; shortages in supplies of drilling rigs and related equipment; shortages in labor; weather conditions; delays in the delivery of equipment; and failure to secure necessary regulatory approvals and permits. Further, 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 activities can result in dry wells and wells that are productive but do not produce sufficient net revenues after operating and other costs and thus may be unprofitable.

We may not be insured against all of the operating risk to which our businesses are exposed. The exploration, development, and production of oil and natural gas and the drilling activities performed by our drilling subsidiary involve risks. These operating risks include the risk of fire, explosions, blow-outs, pipe failure, damaged drilling and oil field equipment, abnormally pressured formations, and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures, or discharges of toxic gases. If any of these industry operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources, and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. Generally, pollution related environmental risks are not fully insurable. We cannot assure that our insurance will be fully adequate to cover these 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 and revenues of such operations, which represented approximately 10% of our 2005 consolidated production costs, and 17% of our 2005 consolidated oil and gas revenues, are denominated in Canadian dollars. As a result, the profitability of our Canadian operations is subject to the risk of fluctuations in the relative value of the Canadian and United States dollars. We have oil and gas assets in other countries including Italy, Gabon and South Africa. Although there are no material operations in these countries, our operations in these countries 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 United States 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. While 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 from these properties. The South African national government has recently adopted legislation to revise the process pursuant to which it grants petroleum exploration and production licenses. Under the new regulations, we have applied to the government to convert one existing prospecting sublease into an exploration right. In addition, we are in the process of applying for a production right covering the geographic area of our other existing prospecting sublease. Because the regulations implementing legislation are not yet final, we cannot predict whether these applications, if granted, will meet our economic or operational requirements, in which event we may choose to relinquish these leases and lose our investment.

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. However, in connection with acquisitions, sometimes our hedges are for longer periods. 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. For example, in 2005, our hedging arrangements reduced the benefits we received from increases in oil and natural gas prices by approximately $222 million. In trying to maintain an appropriate balance, we may end up hedging too much or too little, depending upon how oil or natural gas prices fluctuate in the future. Also, hedging 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 Note 8 to the Consolidated Financial Statements.

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 in acquiring desirable oil and gas properties and in obtaining 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 growth may partially depend on our ability to acquire oil and gas properties on a profitable basis. Acquisition of producing oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. The success of any acquisition will depend on a number of factors, including the acquisition price, future oil and gas prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties, and future abandonment and possible future environmental liabilities. When acquiring new properties, there are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results from an acquisition may vary substantially from those assumed in the purchase analysis and acquired properties may not produce as expected, or there may be conditions that subject us to increased costs and liabilities including environmental liabilities.

We operate a drilling subsidiary and it involves many operating risks, any one of which could prevent us from realizing profits. Forest seeks to increase its oil and gas reserves, production, and cash flow through exploratory and development drilling activities and conducting other production enhancement activities. In 2005, Forest formed a drilling subsidiary to hold drilling equipment and related assets that it acquired in a corporate transaction. The subsidiary performs services for Forest and its subsidiaries as well as third parties. Forest believes these new operations complement its business model and will lessen its exposure to the risks and delays associated with obtaining drilling equipment from third parties in an intensely competitive market. The drilling subsidiary is subject to risks, including shortages in labor and the risks associated with drilling oil and gas wells. These risks include: fires; explosions; blow-outs and surface cratering; pipe failures; casing collapses; natural disasters; and environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases. If any of these events occur, we could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, and environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of our operations. Also, we have experienced significant increases in 2005 and 2006 in oil field service costs and encountered competition for equipment and skilled personnel. Rising costs and tight demand for drilling equipment and personnel in 2006 and could substantially impact the economic viability of our projects.

Our oil and gas operations are subject to various environmental and other governmental regulations that materially affect our operations. Our oil and gas operations are subject to various United States 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 discharge of waste and other substances generated in connection with drilling and production 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 may restrict the rates of flow of oil and gas wells below actual production capacity. A substantial spill from one of our facilities could have a material adverse effect on our results of operations, competitive position, or financial condition. United States and non-United States 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 have limited control over the activities on properties we do not operate. Although we operate the properties from which most of our production is derived, other companies operate some of our other properties. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. The success and timing of drilling development activities on properties developed by others depend upon a number of factors that are outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants, and selection of technology. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns on capital or lead to unexpected future costs.

The Spin-off closing and transition activities may divert management's attention away from normal operations. The Spin-off and Merger were completed on March 2, 2006. Implementing the Spin-off and Merger with Mariner included separating our offshore operations from Forest and has involved complexities and a great deal of time and effort by Forest employees. Going forward, for a limited period of time expiring in September 2006, Forest has agreed to provide Mariner with certain transitional services. The process of completing the Spin-off and Merger in the first quarter of 2006 and the performance of transitional activities following the Spin-off may cause Forest to experience interruptions in its remaining operations or slow its momentum in the completion of new projects as a result of employees' attention being diverted on post-closing activities.

If we fail to realize the anticipated benefits of the Spin-off, Forest shareholders may experience lower returns than expected. The success of Forest following the completion of the Spin-off will depend, in large part, on our ability to realize expected benefits associated with a highly focused strategy, concentrated on long-lived assets. The new model is expected to provide Forest with a foundation for sustainable growth. Initially, the Spin-off will result in a significant reduction in our oil and gas reserves and production volumes and cash flow. We expect to make substantial capital investments for the exploration and development of new oil and gas reserves to replace the reserves and production volumes that are associated with the offshore Gulf of Mexico operations included in the Spin-off. Our ability to replace reserves may be negatively impacted if we are not able to quickly adjust our cost structures, realign staff and responsibilities, generate sufficient cash flow to fund capital investments for the acquisition, exploration, and development of new oil and gas properties, and successfully identify and acquire new properties. If we are not successful in our exploration and development activities and acquisition activities, it will negatively impact our rate of reserve and production growth, cause us to delay or defer capital expenditures, and impact our results of operations.

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

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 2. Properties.

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

Item 3. Legal Proceedings.

Forest, in the ordinary course of business, is a party to various lawsuits, claims, and proceedings, including the matter 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.

Environmental Matters

Forest is involved in a number of governmental proceedings in the ordinary course of business, including the environmental matter described below.

Forest owns and operates a platform located in federal waters of the Cook Inlet off the coast of Alaska. For a period of time, wastewater discharges from the platform exceeded the limits allowed by the National Pollutant Discharge Elimination System permit issued by EPA. Although Forest believes that it is now in compliance with the discharge permits limits, the EPA initiated a formal enforcement proceeding against Forest in October 2005 that seeks to impose fines and penalties for past violations. We believe that the enforcement proceeding related to the past discharges could result in total monetary penalties that should be less than $900,000.

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, 2005.

Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of March 6, 2006.

Name	Age	Years with Forest	Office[1]
H. Craig Clark	49	5	President and Chief Executive Officer, and a member of the Board of Directors since July 2003. Mr. Clark joined Forest in September 2001 as President and Chief Operating Officer. He was appointed President and Chief Executive Officer on July 31, 2003. Mr. Clark was previously employed by Apache 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 ProEnergy, an affiliate of Apache.
David H. Keyte	49	18	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 until December 1995.
Cecil N. Colwell	55	17	Senior Vice President—Worldwide Drilling since May 2004. Between 2000 and May 2004, Mr. Colwell served as our Vice President—Drilling, and from 1988 to 2000 he served as our Drilling Manager—Gulf Coast.
Leonard C. Gurule	49	3	Senior Vice President—Alaska since September 2003. From 1987 to 2000, he served in various capacities at Atlantic Richfield Co. 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.

Name	Age	Years with Forest	Office[1]
J.C. Ridens	50	2	Senior Vice President—Southern Region (formerly Gulf Coast Region) since April 2004. From 2001 to 2004, Mr. Ridens was employed by Cordillera Energy Partners, LLC, as Vice President of Operations and Exploitation. From 1996 to 2001, he served in various capacities at Apache Corporation.
R. Scot Woodall	44	6	Senior Vice President—Western Region since March 2005. He served as our Vice President—Western Region from March 2004 to March 2005. Mr. Woodall joined Forest in October 2000 and previously served as Production and Engineering Manager for the Western Region. From 1993 to September 2000, he served as Operations and Engineering Manager—Rocky Mountain Division, at Santa Fe Snyder Corporation.
Matthew A. Wurtzbacher	43	7	Senior Vice President—Corporate Planning and Development since May 2003. From December 2000 to May 2003, Mr. Wurtzbacher 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.
Cyrus D. Marter IV	42	4	Vice President, General Counsel and Secretary since January 2005. Mr. Marter served as Senior Counsel for Forest from June 2002 until October 2004, at which time he became Associate General Counsel. Prior to joining Forest, Mr. Marter was a partner in the law firm of Susman Godfrey L.L.P. in Houston, Texas.
Victor A. Wind	32	1	Corporate Controller. Mr. Wind joined Forest in January 2005. Mr. Wind was previously employed by Evergreen Resources, Inc. from July 2001 to December 2004. He served in various management positions during this period, including Director of Financial Reporting and Controller. From 1997 to 2001, he served in various capacities at BDO Seidman, L.L.P.

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

PART II

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

Common Stock

Forest has one class of common shares outstanding, its common stock, par value $.10 per share ("Common Stock"). Forest's Common Stock is traded on the New York Stock Exchange under the symbol "FST." On February 28, 2006, there were 62,756,723 outstanding shares of our Common Stock held by 981 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 2004 and 2005. There were no dividends declared on the Common Stock in 2004 or 2005. On March 6, 2006, the closing price of Forest Common Stock was $34.54, which price reflects the special stock dividend distribution on March 2, 2006. See Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations," for details concerning the Spin-off.

		High	Low
2004	First Quarter	$29.60	23.47
	Second Quarter	27.67	23.24
	Third Quarter	30.56	24.35
	Fourth Quarter	34.12	28.17
2005	First Quarter	$43.29	28.87
	Second Quarter	44.00	34.21
	Third Quarter	54.76	40.77
	Fourth Quarter	54.25	40.26

Warrants

At December 31, 2005, Forest did not have any warrants outstanding. During 2005, two series of warrants expired, including warrants that expired on February 15, 2005 ("2005 Warrants") in accordance with the terms of the warrants. In April 2005, Forest provided notice of acceleration of subscription warrants ("Subscription Warrants") that were originally set to expire on March 20, 2010, and on May 9, 2005 all of the remaining unexercised Subscription Warrants expired.

In conjunction with the expiration of the 2005 Warrants and Subscription Warrants during 2005, a total of 1,907,333 warrants to purchase shares of Common Stock were exercised. As a result of these exercises, Forest received cash proceeds of $14.4 million and issued a total of 1,358,350 shares of Common Stock. The warrants that expired in 2005 were originally issued by Forcenergy Inc in connection with its reorganization under the federal bankruptcy code. Upon the merger of Forcenergy and Forest, the warrants became warrants to acquire shares of Forest Common Stock. The issuance of the warrants and shares of Common Stock upon exercise were exempt from registration under the Securities Act of 1933 pursuant to section 1145 of the federal bankruptcy code.

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 7¾% Senior Notes due 2014, and (iii) Forest's United States and Canadian bank credit facilities dated as of September 29, 2004. The provisions in the indentures pertaining to these

Senior Notes and in the bank credit facilities limit our ability to make restricted payments, which include dividend payments.

Forest has not paid cash dividends on its Common Stock during the past five years. The future payment of cash dividends, if any, on the Common Stock is within the discretion of the Board of Directors and will depend on Forest's earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that Forest will pay any cash dividends.

On February 10, 2006, Forest declared a special stock dividend payable to holders of record of Forest Common Stock as of the close of business on February 21, 2006, in connection with the Spin-off that was completed on March 2, 2006. In October 2005, Forest amended its credit facilities to permit the Spin-off, which involved a special stock dividend that was paid in shares of common stock of FERI, which were subsequently exchanged for shares of Mariner upon completion of the Merger. See Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operation," for more details concerning the Spin-off. For further information regarding our equity securities and our ability to pay dividends on our Common Stock, see Notes 4 and 6 to the Consolidated Financial Statements.

For equity compensation plan information, see Part III, Item 12—"Security Ownership of Certain Beneficial Owners and Related Stockholder Matters," below.

Item 6. Selected Financial Data.

The following table sets forth selected financial and operating data of Forest as of and for each of the years in the five-year period ended December 31, 2005. This data should be read in conjunction with Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations," below, and the Consolidated Financial Statements and Notes thereto.

	Years Ended December 31,				
	2005	2004	2003	2002	2001
	(In Thousands Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Revenue:					
Oil and gas sales	$1,062,517	909,780	655,193	471,740	714,852
Marketing, processing, and other	9,528	3,118	1,985	1,128	(85)
Total revenue	1,072,045	912,898	657,178	472,868	714,767
Earnings from continuing operations	151,568	123,126	90,228	21,083	106,437
(Loss) income from discontinued operations, net of tax[1]	—	(575)	(7,731)	193	(2,694)
Cumulative effect of change in accounting principle, net of tax[2]	—	—	5,854	—	—
Net earnings	$ 151,568	122,551	88,351	21,276	103,743
Basic earnings per share:					
Earnings from continuing operations	$ 2.47	2.16	1.82	.45	2.23
(Loss) income from discontinued operations, net of tax	—	(.01)	(.15)	—	(.05)
Cumulative effect of change in accounting principle, net of tax	—	—	.12	—	—
Basic earnings per common share	$ 2.47	2.15	1.79	.45	2.18
Diluted earnings per share:					
Earnings from continuing operations	$ 2.41	2.12	1.79	.44	2.16
(Loss) income from discontinued operations, net of tax	—	(.01)	(.15)	—	(.05)
Cumulative effect of change in accounting principle, net of tax	—	—	.11	—	—
Diluted earnings per common share	$ 2.41	2.11	1.75	.44	2.11
Total assets	$3,645,546	3,122,505	2,683,548	1,924,681	1,796,369
Long-term debt	$ 884,807	888,819	929,971	767,219	594,178
Shareholders' equity	$1,684,522	1,472,147	1,185,798	921,211	923,943
OPERATING DATA					
Annual production:					
Gas (MMcf)	101,833	107,366	96,977	92,068	108,394
Liquids (MBbls)	10,568	10,837	8,701	8,657	10,600
Average sales price[3]:					
Gas (per Mcf)	$ 6.36	5.34	4.53	3.13	4.32
Liquids (per Bbl)	$ 39.23	31.05	24.77	21.16	23.31
Capital expenditures, net of proceeds from asset sales[4]	$ 824,045	605,133	716,554	352,812	416,316

(1) Discontinued operations relate to the sale of the business assets of our Canadian marketing subsidiary on March 1, 2004. The results for this business' operations have been reported as discontinued operations in the selected financial data for all periods presented.

(2) Cumulative effect of change in accounting principle for 2003 relates to the adoption of SFAS No. 143 on January 1, 2003. See Note 1 to the Consolidated Financial Statements.

(3) Includes the effects of hedging.

(4) Does not include estimated discounted asset retirement obligations of $16.3 million, $14.1 million, and $63.7 million related to assets placed in service during the years ended December 31, 2005, 2004, and 2003, respectively.

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

All expectations, forecasts, assumptions, and beliefs about our future financial results, condition, operations, strategic plans, and performance are forward-looking statements, as described in more detail in Part I, Item 1 under the heading "Forward-Looking Statements." Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed in Item 1A under the heading "Risk Factors," 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 the Notes to Consolidated Financial Statements.

Overview

Forest is an independent oil and gas company engaged in the exploration, development, acquisition, and production of natural gas and liquids primarily in North America.

Recent Developments

Spin-off of Offshore Gulf of Mexico Operations

On March 2, 2006, Forest completed the spin-off of its offshore Gulf of Mexico operations by means of a special stock dividend, which consisted of a pro rata spin-off (the "Spin-off") of all outstanding shares of Forest Energy Resources, Inc. ("FERI"), a total of 50,637,010 shares of common stock, to holders of record of Forest common stock as of the close of business on February 21, 2006. Immediately following the Spin-off, FERI was merged with a subsidiary of Mariner Energy, Inc. ("Mariner") in a stock for stock transaction (the "Merger"). Mariner commenced trading on the New York Stock Exchange on March 3, 2006.

The Spin-off was completed without the payment of consideration by Forest shareholders and consisted of a special stock dividend of 0.8093 shares of FERI for each outstanding share of Forest common stock. The Merger was accomplished by the exchange of all issued and outstanding shares of FERI for shares of common stock of Mariner, with each whole share of FERI exchanged for one share of Mariner common stock. The Spin-off is intended to be a tax-free transaction for federal income tax purposes. Prior to the Merger, as part of the Spin-off, FERI paid Forest an initial cash amount equal to approximately $176 million. The cash amount is subject to further adjustment to reflect an economic effective date for the transaction of July 1, 2005.

Cotton Valley Acquisition

On February 13, 2006, Forest announced plans to acquire assets located primarily in the Cotton Valley trend in East Texas. Forest agreed to pay approximately $255 million, subject to customary adjustments, for properties with an estimated 110 Bcfe of proved reserves and production that averaged 13 MMcfe per day in January 2006. In addition to the reserves and production, Forest will also gain approximately 26,000 net acres in the fields, of which approximately 14,000 net acres are undeveloped. The transaction is expected to close in March 2006 and is subject to customary closing conditions. This acquisition is expected to provide another core area of growth and add significant onshore activity to the Southern business unit.

2005 Highlights

Highlights of Forest's performance in 2005 were:

- Increased Revenue: Oil and gas sales exceeded $1 billion despite hurricane activity that deferred approximately 16 Bcfe of production.
- Increased Reserves: Forest's year-end estimated proved reserves were 1,467 Bcfe, 10% higher than year-end 2004, notwithstanding 165.2 Bcfe of production in 2005 and oil and gas property sales of 15.0 Bcfe.
- Exploration and Development Track Record: Forest had continuing success in 2005 with its Buffalo Wallow project and Foothills/Wild River projects in Canada. Drilling well counts for 2005 increased to a record 392 (196 without San Juan wells), with a 97% success rate.
- Acquisition Accomplishments: Forest invested $314 million (including approximately $71 million of deferred tax gross up and excluding $23 million of goodwill each recorded in connection with a business combination) to acquire 127 Bcfe of estimated proved reserves.
- Reduced Leverage: Forest ended the year with a total debt-to-book capitalization ratio of 34%.

Hurricane Impact

During 2005, our Gulf of Mexico operations were adversely affected by one of the most active hurricane seasons in recorded history. As of December 31, 2005, Forest had approximately 70 MMcfe per day of net production shut-in relating to Forest's offshore Gulf of Mexico operations. Forest estimates that total production operations deferred for hurricanes Katrina and Rita in the third and fourth quarters of 2005 was approximately 16 Bcfe.

We carry property and casualty insurance to insure against property damages such as those caused by hurricanes. The insurance has a $5 million deductible for each occurrence. Our estimated uninsured liability for the repair of our facilities damaged by hurricanes in the third quarter of 2005 is $10 million, the majority of which was incurred in the fourth quarter of 2005 as the related expenditures were made. Forest's insurance does not include business interruption for shut-in production.

As a result of the completion of the Spin-off, the residual effects of the 2005 hurricanes on our operations have been largely eliminated. We expect that the risks associated with future hurricane activity will be largely diminished although production interruptions may still occur to the extent third party transportation and processing facilities are damaged or if our onshore properties suffer damage.

2006 Outlook

In 2006, we expect to focus on our onshore North American assets by accelerating our development and exploitation activities on legacy and newly acquired fields. Our capital budget for 2006 is $425 million to $475 million, not including capital expenditures planned in the Cotton Valley area of East Texas pending the closing of the acquisition scheduled for March 31, 2006. Of this total, approximately 40% is expected to be directed to our large drilling programs in Buffalo Wallow, Wild River, and the Greater Haley area.

We also anticipate a continued favorable commodity price environment in 2006. In our view, the economic growth and the related increased demand for oil and gas should continue to support relatively high commodity prices. Within this environment, we anticipate strong financial performance by Forest. Our inventory of exploitation and exploration projects is at a high level, which should provide us good visibility of future production growth in our remaining onshore business. Our 2006 plan anticipates cash flow from operations greater than our exploration and development spending levels, which is expected to be used, in whole or in part, to fund acquisitions.

We face numerous challenges in 2006. We will be challenged in transitioning our focus to onshore oil and gas operations following the Spin-off. Among other matters, we must realign staff and responsibilities, adopt appropriate cost structures, and transition the offshore Gulf of Mexico operations to Mariner. However, as a result of the Spin-off, we no longer have the challenges associated with the offshore Gulf of Mexico operations that were subject to inherent high production declines and disruptions from hurricanes. We expect to continue to pursue asset acquisition opportunities in 2006, but expect to continue to confront intense competition for these assets. Also, due to a relatively high commodity price environment, we anticipate service costs as well as costs of equipment and raw materials to remain at or exceed the high levels set in 2005. Our challenge will be to add reserves, through drilling and acquisitions, and operate our productive assets cost-efficiently in a manner that achieves attractive returns for our shareholders.

Results of Operations

For the year ended December 31, 2005, Forest reported net earnings of $151.6 million or $2.47 per basic share, a 24% increase compared to net earnings of $122.6 million or $2.15 per basic share in the corresponding 2004 period. The increase in earnings in 2005 compared to 2004 was primarily the result of increased average oil and gas sales prices, offset partially by decreased sales volumes due to production deferrals from the 2005 hurricane season and related per-unit increases in oil and gas production expense. For the year ended December 31, 2004, Forest reported net earnings of $122.6 million or $2.15 per basic share, a 39% increase compared to net earnings of $88.4 million or $1.79 per basic share in the corresponding 2003 period. The increase in earnings in 2004 compared to 2003 was due primarily to the combination of increased average oil and gas sales prices and increased sales volumes, offset partially by increased oil and gas production expense and increased depletion expense. Discussion of the components of the changes in our annual results follows.

Oil and Gas Sales

Production volumes, revenues, and weighted average sales prices, by product and location for the years ended December 31, 2005, 2004, and 2003 are set forth in the table below.

	Year Ended December 31,											
	2005				2004				2003			
	Gas	Oil	NGLs	Total	Gas	Oil	NGLs	Total	Gas	Oil	NGLs	Total
	(MMcf)	(MBbls)	(MBbls)	**(MMcfe)**	(MMcf)	(MBbls)	(MBbls)	**(MMcfe)**	(MMcf)	(MBbls)	(MBbls)	**(MMcfe)**
Production volumes:												
United States	82,912	7,412	1,904	**138,808**	91,420	8,396	1,154	**148,720**	84,368	7,221	465	**130,484**
Canada	18,921	844	408	**26,433**	15,946	897	390	**23,668**	12,609	629	386	**18,699**
Totals	101,833	8,256	2,312	**165,241**	107,366	9,293	1,544	**172,388**	96,977	7,850	851	**149,183**
Revenues (in thousands):												
United States	$624,457	391,226	56,375	**1,072,058**	557,224	329,432	30,063	**916,719**	444,483	209,958	8,639	**663,080**
Canada	126,771	35,382	14,748	**176,901**	67,398	31,839	10,953	**110,190**	38,943	17,973	8,060	**64,976**
Hedging effects(1)	(103,292)	(83,150)	—	**(186,442)**	(51,280)	(65,849)	—	**(117,129)**	(43,726)	(29,137)	—	**(72,863)**
Totals	$647,936	343,458	71,123	**1,062,517**	573,342	295,422	41,016	**909,780**	439,700	198,794	16,699	**655,193**
Average sales price:												
United States	$ 7.53	52.78	29.61	**7.72**	6.10	39.24	26.05	**6.16**	5.27	29.08	18.58	**5.08**
Canada	6.70	41.92	36.15	**6.69**	4.23	35.49	28.08	**4.66**	3.09	28.57	20.88	**3.47**
Hedging effects(1)	(1.01)	(10.07)	—	**(1.13)**	(.48)	(7.09)	—	**(.68)**	(.45)	(3.71)	—	**(.49)**
Totals	$ 6.36	41.60	30.76	**6.43**	5.34	31.79	26.56	**5.28**	4.53	25.32	19.62	**4.39**

(1) Commodity swaps and collars were transacted to hedge the price of spot market volumes against price fluctuations. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk," below, concerning our hedging activities.

The increase in oil and gas sales revenue of $152.7 million in 2005 compared to 2004 was the result of a 22% increase in price realizations per Mcfe partially offset by a 4% decrease in production. The decrease in our sales volumes between the same periods of 7.1 Bcfe was due primarily to approximately 16 Bcfe of deferred production due to hurricanes Katrina and Rita that primarily impacted our offshore Gulf of Mexico properties, offset by increases in our onshore North American production.

The increase in oil and gas sales revenue of $254.6 million in 2004 compared to 2003 was the result of a 20% increase in price realizations per Mcfe, combined with a 16% increase in sales volumes. The increase in sales volumes was attributable primarily to acquisitions made during the fourth quarter of 2003 and the second quarter of 2004.

Oil and Gas Production Expense

The table below sets forth the detail of oil and gas production expense for the years ended December 31, 2005, 2004, and 2003:

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands Except Per Mcfe Amounts)		
Lease operating expenses ("LOE"):			
Direct operating expense and overhead	$166,119	165,983	119,569
Workover expense	30,011	21,058	4,913
Hurricane repairs	3,631	2,120	—
Total LOE	$199,761	189,161	124,482
LOE per Mcfe	$ 1.21	1.10	.83
Production and property taxes	$ 42,615	32,241	19,929
Production and property taxes per Mcfe	$ .26	.19	.13
Transportation costs	$ 19,499	16,792	9,759
Transportation costs per Mcfe	$ .12	.10	.07

Lease Operating Expenses

As reflected in the table above, direct operating expenses and overhead increased only marginally in 2005 compared to 2004 while increases in workover costs made up the majority of the $10.6 million increase in LOE. On a per-unit basis, total LOE increased 10% to $1.21 per Mcfe in of 2005 from $1.10 per Mcfe in 2004 due primarily to hurricane activity in the third quarter of 2005 that deferred approximately 16 Bcfe of production.

LOE increased approximately $64.7 million from 2003 to 2004. LOE from the properties acquired in late 2003 and during 2004 accounted for approximately 60% of the increase. The acquired properties had higher initial LOE due to deferred maintenance of the properties at the time of acquisition. Forest also spent approximately $16.1 million more in 2004 on workovers than it did in 2003; approximately $4.9 million of the increase related to the properties acquired in 2003 and 2004.

Production and Property Taxes

Production and property taxes increased $10.4 million in 2005 to $42.6 million as compared to $32.2 million in 2004. From 2003 to 2004, production and property taxes increased $12.3 million. The increases in each period were primarily a result of the higher realized oil and gas revenues and higher assessed property valuations. As a percentage of oil and natural gas revenue, excluding hedging losses, production and property taxes were 3.4%, 3.1%, and 2.7% for the years ended December 31, 2005, 2004, and 2003, respectively. The increases in each period is primarily the result of a change in our production mix over the last few years to a higher percentage of onshore production, which is generally subject to production taxes, versus offshore production, which is generally not subject to production taxes.

Transportation Costs

Transportation costs were $19.5 million, $16.8 million, and $9.8 million for the years ended December 31, 2005, 2004 and 2003, respectively. The increased costs were a result of increases in gathering and transportation rates, as well as increases in fuel prices. On an equivalent Mcfe basis, transportation costs were $.12, $.10, and $.07 per Mcfe for the years ended December 31, 2005, 2004 and 2003, respectively.

General and Administrative Expense; Overhead

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

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands Except Per Mcfe Amounts)		
Total overhead costs	$70,209	56,114	60,841
Overhead costs capitalized	26,506	23,969	24,519
Total overhead costs expensed	$43,703	32,145	36,322
General and administrative expense per Mcfe	$ .26	.19	.24

The increase in total overhead costs and overhead costs expensed in 2005 as compared to 2004 was primarily related to an increase in salaries and related burdens caused by our hiring additional employees in conjunction with our recent acquisitions and general increases in salaries due to an increasingly competitive market for experienced oil and gas professionals. The percentage of overhead capitalized remained relatively constant between the three years reflected in the table above, ranging between 38% and 43%. The percentage of overhead capitalized in 2005 of 38% was lower than the 43% of overhead capitalized in 2004 due primarily to increases in general corporate costs.

Depreciation and Depletion; Undeveloped Properties

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands Except Per Mcfe Amounts)		
Depreciation and depletion expense	$368,679	354,092	234,822
Depreciation and depletion expense per Mcfe	$ 2.23	2.05	1.57

The increases in depreciation and depletion expense on an equivalent unit of production basis of $.18 in 2005 compared to 2004 was due primarily to higher anticipated drilling and completion costs on future development activities as well as the effect of property divestitures in Canada in late 2004. The increase in depreciation and depletion expense on an equivalent unit of production basis of $.48 in 2004 compared to 2003 was due primarily to downward revisions in estimated proved reserves in the fourth quarter of 2003. See discussion of the revision to the estimated proved reserves in Note 14 to the Consolidated Financial Statements.

The following costs of undeveloped properties were not subject to depletion at the periods indicated:

December 31,	United States	Canada	International	Total
		(In Thousands)		
2005	$174,249	44,798	56,637	275,684
2004	106,908	46,730	55,966	209,604
2003	66,339	34,922	56,747	158,008

The increase in the total undeveloped properties from 2004 to 2005 was due primarily to the additional undeveloped properties acquired in 2005 in conjunction with the Buffalo Wallow acquisition. The increase in the total undeveloped properties from 2003 to 2004 was due primarily to the additional undeveloped properties acquired in 2004 in conjunction with the purchase of Wiser. See Note 2 to the Consolidated Financial Statements for additional information on the Buffalo Wallow and Wiser acquisitions.

Accretion of Asset Retirement Obligations

Accretion expense of approximately $17.3 million in both 2005 and 2004, and $13.8 million in 2003 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 to adopt SFAS No. 143, Forest recorded an after tax credit of approximately $5.9 million in the first quarter of 2003.

International Impairments

In 2005, Forest recorded an impairment of $2.9 million related to certain international properties, principally related to its leaseholds in Romania. The Romania impairment was recorded in the first quarter of 2005 in connection with our decision to exit the country as we rationalize our international assets to concentrate on fewer areas. In 2004, Forest recorded impairments of oil and gas properties located outside of North America of $4.0 million related to evaluations of projects in Albania, Germany, and Italy. In 2003, we recorded impairments of $16.9 million, related primarily to evaluations of projects in Albania, Italy, Romania, Switzerland, and Tunisia. Of this amount, approximately $10.3 million related to our interest in a project in Albania.

Interest Expense

Interest expense of $61.4 million in 2005 was 6% greater than 2004, primarily due to higher average interest rates partially offset by lower average debt balances. Interest expense of $57.8 million in 2004 was 17% greater than 2003, due primarily to higher average debt balances.

Realized and Unrealized Losses on Derivative Instruments

Realized and unrealized gains and losses on derivative instruments are primarily related to various derivatives that did not qualify for cash flow hedge accounting either at their inception or during their term. When the criteria for cash flow hedge accounting are not met, realized gains and losses (i.e., cash settlements) are recorded in other income (expense) in the Consolidated Statements of Operations. Similarly, changes in the fair value of the derivative instruments are recorded as unrealized gains or losses in the consolidated statements of operations. In contrast, cash settlements for derivative instruments that qualify for hedge accounting are recorded as additions to or reductions of oil and gas revenues while 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.

The table below sets forth realized and unrealized gains and losses principally related to our derivatives that did not qualify for hedge accounting for the periods indicated.

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Realized (losses) gains	$(35,390)	336	(68)
Unrealized (losses) gains	(21,373)	(1,088)	451

The significant increases in realized and unrealized losses on derivative instruments in 2005 are primarily related to the loss of hedge accounting on many of our commodity derivatives in the third and fourth quarters of 2005 due to hurricanes Rita and Katrina. Additionally, several commodity collars that were assumed in recent acquisitions (as discussed in Note 2 to the Consolidated Financial Statements) were not eligible for cash flow hedge accounting treatment.

For comparative purposes, the following table sets forth, for the periods indicated, realized losses on derivative instruments that met the criteria for hedge accounting, which were recorded as reductions of oil and gas revenues.

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Realized losses included in oil and gas revenue	$(186,442)	(117,129)	(72,863)

In addition to the realized losses reflected in the tables above, Forest settled approximately $15.2 million in hedge losses in the fourth quarter of 2005 that were deferred until the first quarter of 2006 to correspond with the timing of the production that was deferred from hurricanes Katrina and Rita.

Other Expense (Income), Net

The components of other expense (income), net for the years ended December 31, 2005, 2004, and 2003 were as follows:

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Loss on extinguishment of debt	$ —	—	3,975
Foreign currency exchange gain	—	(4,728)	—
Franchise taxes	1,963	1,219	1,679
Share of loss (income) of equity method investee	562	(1,726)	2,043
Other, net	3,722	3,056	(350)
Total other expense (income), net	$6,247	(2,179)	7,347

The foreign currency exchange gain in 2004 is related to the repayment of Canadian intercompany debt denominated in U.S. dollars. 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 statute. Forest's share of income or loss of equity method investee relates to our 40% ownership of a pipeline company that transports crude oil in Alaska. Loss on extinguishment of debt relates to redemptions of our 10½% Senior Subordinated Notes for amounts in excess of par value.

Current and Deferred Income Tax Expense

Forest recorded current income tax expense before discontinued operations and cumulative effect of change in accounting principle of $3.5 million in 2005 compared to $3.0 million in 2004 and $.7 million in 2003. The majority of the current income tax provision in 2005 relates to federal and state tax imposed on a dividend received from our Canadian subsidiary. We chose to repatriate these funds from our Canadian subsidiary to take advantage of a special one-time dividends received deduction on the repatriation of certain foreign earnings introduced by the American Jobs Creation Act of 2004. Current tax expense in each of 2004 and 2003 was due primarily to federal alternative minimum tax and to state income taxes.

Deferred income tax expense before discontinued operations and cumulative effect of change in accounting principle was $89.9 million in 2005 compared to $75.8 million in 2004 and $53.9 million in 2003. The increase in each of the years was due primarily to increased net income before income taxes, partially offset by a decrease in Canadian taxes of $3.1 million, $2.4 million, and $7.3 million, respectively, due to reductions in Canadian federal and provincial tax rates.

In total, Forest's effective income tax rates for the years ended December 31, 2005, 2004, and 2003, were 38.1%, 39.0%, and 37.7%, respectively. These rates were based on a U.S. federal statutory rate of 35.0% in each of the three years. Differences between the U.S. federal statutory rate and the effective rate were primarily due to foreign and state statutory rates and permanent book to tax differences. Refer to Note 5 to the Consolidated Financial Statements for a reconciliation of our income taxes at the statutory rate to income taxes at our effective rate for each period presented.

Results of Discontinued Operations

On March 1, 2004, the assets and business operations of our Canadian marketing subsidiary were sold to Cinergy Canada, Inc. ("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 through February 2009 (unless subject to prior contractual commitment), and will also administer the netback pool that we formerly administered. We could receive additional contingent payments related to this sale over the next four years if Cinergy meets certain earnings goals with respect to the acquired business. The subsidiary's results of operations have been reported as discontinued operations in the consolidated statements of operations for all years presented. The components of loss from discontinued operations for the years ended December 31, 2004 and 2003 are as follows:

	Years Ended December 31,	
	2004	2003
	(In Thousands)	
Marketing income, net	$ 597	2,728
General and administrative expense	(280)	(1,921)
Interest expense	(2)	(59)
Other (expense) income	(166)	606
Depreciation	—	(1,325)
Current income tax (expense) benefit	(2)	27
Deferred income tax expense	(722)	(2,623)
Loss on sale of discontinued operations	—	(5,164)
Loss from discontinued operations, net of tax	$(575)	(7,731)

Liquidity and Capital Resources

In 2006, as in 2005, we expect our cash flow from operations to be our primary source of liquidity to meet operating expenses and fund capital expenditures other than large acquisitions. Any remaining cash flow from operations will be available for acquisitions, in whole or in part, or other corporate purposes, including the repayment of indebtedness.

The prices we receive for our oil and natural gas production have a significant impact on operating cash flows. While significant price declines in 2006 would adversely affect the amount of cash flow generated from operations, we utilize a hedging program to partially mitigate that risk. As of March 3, 2006, Forest has hedged approximately 43 Bcfe of its estimated 2006 onshore North American and Alaskan offshore production. This level of hedging provides certainty of the cash flow we will receive for a large portion of our expected 2006 production. Depending on changes in oil and gas futures markets and management's view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current hedging positions. For further information concerning our 2006 hedging contracts, see Item 7A—"Quantitative and Qualitative Disclosures about Market Risk—Hedging Program," below.

Our $600 million revolving bank credit facilities, which we entered into in September 2004, provide another source of liquidity. These credit facilities, which mature in September 2009, are used to fund daily operating activities and acquisitions in the United States and Canada as needed. At March 3, 2006, we had approximately $66 million of outstanding borrowings and letters of credit under the bank credit facilities, and an unused borrowing base of $534 million. On February 13, 2006 we announced plans to acquire assets in the Cotton Valley of East Texas, for a purchase price of $255 million. The transaction is scheduled to close on March 31, 2006, subject to customary closing conditions, and we plan to use cash on hand and availability under our credit facilities to fund this acquisition.

On March 2, 2006, we completed the Spin-off of our offshore Gulf of Mexico operations. These operations accounted for approximately 40% of our total oil and gas production in 2005 and 37% of our consolidated oil and gas revenues for the year ended December 31, 2005. As a result of the Spin-off, we expect future cash flows from operations to be significantly lower; however, we also expect a significant decrease in capital expenditures and payments for asset retirement obligations. In connection with the Spin-off, we received an initial payment of approximately $176 million (subject to certain post-closing adjustments to reflect an economic effective date for the transaction of July 1, 2005), which we used to pay down our credit facilities. We do not believe the Spin-off will have a material effect on our liquidity and capital resources nor do we believe it will materially adversely effect our ability to access the capital markets.

The public capital markets have been our principal source of funds to finance large acquisitions. We have sold debt and equity securities in both public and private offerings in the past, and we expect that these sources of capital will continue to be available to us in the future for acquisitions. In July 2004, we filed a shelf registration statement that allows Forest to issue equity and debt securities of up to $600 million, all of which is still available. Nevertheless, ready access to capital on reasonable terms can be impacted by our debt ratings assigned by independent rating agencies and are subject to many uncertainties, including restrictions contained in our bank credit facilities and indentures for our senior notes, macroeconomic factors outside of our control, and other risks as explained in Part 1, Item 1A—"Risk Factors."

We believe that our available cash, cash provided by operating activities, and funds available under our bank credit facilities will be sufficient to fund our operating, interest, and general and administrative expenses, our capital expenditure budget, and our short-term contractual obligations at current levels for the foreseeable future.

Bank Credit Facilities

We currently 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 September 2009. Subject to the agreement of Forest and the applicable lenders, the size of the credit facilities may be increased by $200 million in the aggregate.

On March 3, 2006, there were no outstanding borrowings under the U.S. facility and there were outstanding borrowings of $59.1 million under the Canadian credit facility at a weighted average interest rate of 5.1%. Together with the $6.9 million in letters of credit outstanding, the unused borrowing amount on March 3, 2006 was approximately $534 million. In connection with the Spin-off, Forest received approximately $176 million from its former subsidiary, FERI, which it used to pay off its borrowings under its U.S. credit facility.

Availability under the credit facilities will be based either on certain financial covenants included in the credit facilities or on the loan value assigned to Forest's oil and gas properties. If Forest's corporate credit rating by Moody's is "Ba1" or higher and "BB+" or higher by S&P, the credit facilities may be governed by certain financial covenants. Alternatively, if Forest's corporate credit rating is "Ba2" or lower by Moody's or "BB" or lower by S&P, availability under the credit facilities will be governed by a borrowing base ("Global Borrowing Base"). Currently, the amount available under the credit facilities is determined the Global Borrowing Base. Effective October 19, 2005, the credit facilities were amended to permit Forest to complete the Spin-off and the Global Borrowing Base was increased to $900 million. On March 2, 2006, concurrent with the completion of the Spin-off, the Global Borrowing Base was reduced to $600 million, with $500 million allocated to the U.S. credit facility and $100 million allocated to the Canadian facility.

At December 31, 2005, there were outstanding borrowings of $97.0 million under the U.S. credit facility at a weighted average interest rate of 5.6%, and there were outstanding borrowings of $56.8 million under the Canadian credit facility at a weighted average interest rate of 4.8%. We also had used the credit facilities for approximately $6.9 million in letters of credit, leaving an unused borrowing amount under the Global Borrowing Base of approximately $439.3 million at December 31, 2005.

The determination of the Global Borrowing Base is made by the lenders taking into consideration the estimated value of Forest's oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. This process involves reviewing Forest's estimated proved reserves and their valuation. While the Global Borrowing Base is in effect, it is redetermined semi-annually, and the available borrowing amount could be increased or decreased as a result of such redeterminations. In addition, Forest and the lenders each have discretion at any time, but not more often than once during any calendar year, to have the Global Borrowing Base redetermined. A revision to Forest's reserves may prompt such a request on the part of the lenders, which could possibly result in a reduction in the Global Borrowing Base and availability under the credit facilities. As described above, in connection with the Spin-off, the Global Borrowing Base was reduced to $600 million. If outstanding borrowings under either of the credit facilities exceed the applicable portion of the Global Borrowing Base, Forest would be required to repay the excess amount within a prescribed period. If we are unable to pay the excess amount, it would cause an event of default.

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, mergers, and acquisitions. The credit facilities also include several financial covenants. Availability, interest rates, security requirements, and other terms of borrowing under the credit facilities will vary based on Forest's credit ratings and financial condition, as determined by certain financial tests. In particular, any time that availability is not determined by the

Global Borrowing Base, the amount available and our ability to borrow under the credit facilities is determined by certain financial covenants. Also, even when availability is determined by the Global Borrowing Base, certain financial covenants may affect the amount available and Forest's ability to borrow amounts under the credit facilities.

The credit facilities are collateralized by a portion of our assets. We are required to mortgage, and grant a security interest in, 75% of the present value of our consolidated proved oil and gas properties. We have also pledged the stock of several subsidiaries to the lenders to secure the credit facilities. Under certain circumstances, we could be obligated to pledge additional assets as collateral. If our corporate credit ratings by Moody's and S&P improve and meet pre-established levels, the collateral requirements would not apply and, at our request, the banks would release their liens and security interests on our properties.

Historical Cash Flow

Net cash provided by operating activities, net cash used by investing activities, and net cash (used) provided by financing activities for the years ended December 31, 2005, 2004, and 2003 were as follows:

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Net cash provided by operating activities	$ 628,565	568,013	381,984
Net cash used by investing activities	(671,230)	(455,901)	(659,181)
Net cash (used) provided by financing activities	(4,596)	(68,269)	274,549

The increase in net cash provided by operating activities in 2005 compared to 2004 of approximately $60.6 million was due primarily to a $42.4 million increase in net income excluding deferred income tax expense. The increase in cash used by investing activities in 2005 of $215.3 million was due primarily to an increase in cash used for the exploration and development of oil and gas properties of $166.2 million and a decrease in proceeds from the sale of assets of $73.9 million. Net cash used by financing activities in 2005 of $4.6 million primarily included the net repayment of bank borrowings of $33.3 million, more than offset by net proceeds from the exercise of options and warrants of approximately $43.4 million.

The increase in net cash provided by operating activities in 2004 compared to 2003 of approximately $186.0 million was due primarily to an increase in net income and depreciation expense (a non-cash expense) totaling $152.1 million. The decrease in cash used by investing activities in 2004 of $203.3 million was due primarily to a decrease in capital expenditures of $265.6 million and an increase in proceeds from the sale of oil and gas properties of $83.5 million, which were offset by an increase in cash used for the acquisitions of oil and gas properties of $141.7 million. Net cash used by financing activities in 2004 of $68.3 million included the net repayment of bank borrowings of $206.9 million, offset partially by net proceeds from the issuance of common stock and the exercise of options and warrants of approximately $140.0 million in the aggregate.

Capital Expenditures

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

	Year Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Property acquisitions:[1]			
Proved properties	$238,942	367,974	420,022
Undeveloped properties	73,868	57,452	4,223
	312,810	425,426	424,245
Exploration:			
Direct costs	245,523	79,676	90,715
Overhead capitalized	12,811	11,917	13,549
	258,334	91,593	104,264
Development:			
Direct costs	252,509	171,166	189,269
Overhead capitalized	13,695	12,052	10,970
	266,204	183,218	200,239
Total capital expenditures[1][2]	$837,348	700,237	728,748

(1) Total capital expenditures include both cash expenditures and accrued expenditures. In addition, property acquisitions include a gross up for deferred income taxes of approximately $71.5 million in 2005, $46.6 million in 2004, and $32.7 million in 2003 and excludes goodwill recorded in connection with business combinations of approximately $23.0 million in 2005 and $64.1 million in 2004. See Note 2 to the Consolidated Financial Statements for the allocation of purchase consideration for the larger acquisitions completed in 2005 and 2004.

(2) Does not include estimated discounted asset retirement obligations of $16.3 million, $14.1 million, and $63.7 million related to assets placed in service during the years ended December 31, 2005, 2004, and 2003.

Forest's anticipated expenditures for exploration and development in 2006 are estimated to range from $425 million to $475 million, not including capital expenditures planned in the Cotton Valley area of East Texas pending the closing of the acquisition on March 31, 2006. Some of the factors impacting the level of capital expenditures in 2006 include crude oil and natural gas prices, the volatility in these prices, the cost and availability of the oil field services, and weather disruptions.

Dispositions of Oil and Gas Properties

As 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 2005, we sold assets, including oil and gas assets with estimated proved reserves of approximately 15.0 Bcfe, for total proceeds of approximately $24.0 million. During 2004, we disposed of oil and gas assets with estimated proved reserves of approximately 84.6 Bcfe for total proceeds of approximately $106.4 million.

Credit Ratings

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.

Our bank credit facilities include conditions that are linked to our credit ratings. The fees and interest rates on our commitments and loans, as well as our collateral obligations, are affected by our credit ratings. The indentures governing our senior notes do not include adverse triggers that are tied to our credit ratings. The indentures include terms that will allow us greater flexibility if our 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. Our ability to raise funds and the costs of any financing activities may be affected by our credit rating at the time any such activities are conducted.

Common Stock Offerings

In June 2004, we issued 5.0 million shares of common stock at a price of $24.40 per share. Net proceeds from this offering were approximately $117.1 million after deducting underwriting discounts and commissions and offering expenses. The net proceeds from the offering were used to fund a portion of the Wiser acquisition.

In October 2003, Forest issued 5.1 million shares of common stock at a price of $23.10 per share. Net proceeds from this offering were approximately $112.6 million after deducting underwriting discounts and commissions and offering expenses. The net proceeds were used to help fund a portion of the purchase price of an acquisition. In January 2003, Forest issued 7.9 million shares of common stock at a price of $24.50 per share. Net proceeds from this offering were approximately $184.4 million after deducting underwriting discounts and commissions and the expenses of the offering. An additional .9 million shares of common stock were issued in February 2003 pursuant to exercise of the underwriters' over-allotment option for net proceeds of $21.2 million. The net proceeds from these offerings were used primarily to repurchase common shares.

Debt Offerings

In July 2004, we issued $125 million in principal amount of 8% Senior Notes due 2011, at 107.75% of par for proceeds of $133.3 million (net of related offering costs). The net proceeds were used to reduce outstanding borrowings under our U.S. credit facility.

Note Redemptions

In July 2004, we redeemed, at 101.583% of par value, $125 million in principal amount of 9½% Senior Subordinated Notes due 2007 that were issued by Wiser. The note redemption was funded using borrowings under our U.S. credit facility.

In January 2003, we redeemed the remaining $66.0 million outstanding principal amount of our 10½% Senior Subordinated Notes at 105.25% of par value, resulting in a loss of $4.0 million which was recorded in the first quarter of 2003.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2005:

	2006	2007	2008	2009	2010	After 2010	Total
				(In Thousands)			
Bank debt[1]	$ 8,138	8,138	8,138	159,909	—	—	184,323
Other long-term debt[2]	55,625	55,625	309,135	34,425	34,425	495,592	984,827
Operating leases[3]	4,821	3,773	3,309	3,032	3,066	15,097	33,098
Unconditional purchase obligations[4]	3,955	2,291	1,779	1,140	789	—	9,954
Other liabilities[5]	37,217	20,253	13,586	20,095	17,143	141,603	249,897
Derivative liabilities[6]	150,737	—	—	—	—	—	150,737
Approved capital projects[7]	44,694	—	—	—	—	—	44,694
Total contractual obligations	$305,187	90,080	335,947	218,601	55,423	652,292	1,657,530

(1) Bank debt consists of commitments related to our United States and Canadian credit facilities and anticipated interest payments due under the terms of the credit facilities using the average interest rate in effect at December 31, 2005.

(2) Other long-term debt consists of the principal obligations on our senior notes and anticipated interest payments due on the notes.

(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.

(5) Other liabilities represent current and noncurrent liabilities that are comprised of benefit obligations and asset retirement obligations, for which neither the ultimate settlement amounts nor their timings can be precisely determined in advance. See "Critical Accounting Policies, Estimates, and Assumptions" below for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

(6) Derivative liabilities represent the fair value of liabilities for oil and gas commodity derivatives as of December 31, 2005. The ultimate settlement amounts of our derivative liabilities are unknown, because they are subject to continuing market risk. See "Critical Accounting Policies, Estimates, Judgments, and Assumptions," below for a more detailed discussion of the nature of the accounting estimates involved in valuing derivative instruments.

(7) Consists of our net share of budgeted expenditures under Authorizations for Expenditure ("AFE") that were approved by us and our joint venture partners as of December 31, 2005. Includes AFEs for which Forest is the operator as well as those operated by others.

In addition to the above commitments, we are obligated to make approximately $16.5 million of capital expenditures over the next two years pursuant to the terms of foreign concession arrangements. Forest also makes delay rental payments to lessors during the primary terms of oil and gas leases to delay drilling or production of wells, usually for one year. Although we are not obligated to make such payments, discontinuing them would result in the loss of the oil and gas lease. Our total maximum commitment under these leases, through 2013 totaled approximately $1.4 million as of December 31, 2005.

Off-balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2005, the off-balance sheet arrangements and transactions that we have entered into include (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, and (iv) contractual obligations for which the ultimate settlement amounts are not fixed and determinable such as derivative contracts that are sensitive to future changes in commodity prices and gas transportation commitments. Forest does not believe that these arrangements are reasonably likely to materially affect its liquidity or availability of, or requirements for, capital resources.

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, 2006, we had 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 $20.4 million. See Part I, Item 1—"Business—Regulation" for further information.

Critical Accounting Policies, Estimates, Judgments, and Assumptions

Critical Estimates

The following items are estimates used in the preparation of our financial statements that management deems to be "critical" in nature because either (i) the accounting estimate requires us to make assumptions about matters that are highly uncertain at the time the accounting estimate is made, and different estimates could have reasonably been used for the accounting estimate in the current period, or (ii) in our judgment changes in the accounting estimate that are reasonably likely to occur from period to period would have a material impact on the presentation of Forest's financial condition, changes in financial condition, or results of operations.

Oil and Gas Reserve Estimates

Our estimates of proved reserves are based on the quantities of oil and gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, production, and property taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and gas properties are also subject to a "ceiling test" limitation based in part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Reference should be made to "*Independent Audit of Reserves*" under Part I, Item 1—"Business," and "*Estimates of oil and gas reserves are uncertain and inherently imprecise*," under Part I, Item 1A—"Risk Factors," in this Form 10-K.

Fair Values of Derivatives

The fair market value of all derivative instruments is recognized as an asset or liability on our balance sheet. The accounting treatment for the changes in fair value is dependent upon whether or not a derivative instrument is: (i) a cash flow hedge or (ii) a fair value hedge, and upon whether or not the derivative qualifies as an effective hedge. Changes in the fair value of effective cash flow hedges are recognized 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 the fair value of the derivative instrument 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 the Consolidated Statement of Operations as other income or expense.

The estimated fair values of the Company's derivative instruments require substantial judgment. These values are based upon, among other things, future prices, volatility, time to maturity, and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions, or other factors, many of which are beyond our control. Another factor that can impact our results of operations each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated, because energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of oil and natural gas prices, the fair values of our derivative instruments are subject to large fluctuations in estimated fair value from period to period. For example, a hypothetical increase or decrease in the forward oil and natural gas prices used to calculate the fair value of the derivative instruments at December 31, 2005 of $1.00 per barrel and $.25 per MMbtu, respectively, would change the fair values of our derivative instruments at December 31, 2005 by approximately $8.6 million. It has been our experience that commodity prices are subject to large fluctuations, and we expect this volatility to continue. Actual gains or losses recognized in conjunction with our commodity derivative contracts will likely differ from those estimated at December 31, 2005 and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

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 value 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 for 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, 2005. 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.

Asset Retirement Obligations

The Company has obligations to remove tangible equipment and restore locations at the end of the oil and gas production operations. Forest's removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms in the Cook Inlet of Alaska. Estimating the future restoration and removal costs, or asset retirement obligations, is difficult and requires management to make estimates and judgments, because most of the obligations are many years in the future, and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

Inherent in the calculation of the present value of our asset retirement obligations ("ARO") under SFAS 143 are numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. Increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense in the Consolidated Statement of Operations.

Critical Policies

The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities: the full-cost method and the successful efforts method. The differences between the two methods can lead to significant variances in the amounts reported in our financial statements. We have elected to follow the full-cost method, which is described below.

Full Cost Method of Accounting

Under the full cost method, separate cost centers are maintained for each country in which we incur costs. All costs incurred in the acquisition, exploration, and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) are capitalized. The fair value of estimated future costs of site restoration, dismantlement, and abandonment activities is capitalized, and a corresponding asset retirement obligation liability is recorded. Capitalized costs applicable to each full cost center are depleted using the units of production method based on conversion to common units of measure using one barrel of oil as an equivalent to six thousand cubic feet of natural gas. Changes in estimates of reserves or future development costs are accounted for 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 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 assess individually the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized in the appropriate full cost pool, or reported as impairment expense in the Consolidated Statements of Operations, as applicable.

Companies that use the full cost method of accounting for oil and gas exploration and development activities are required to perform a ceiling test each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed each quarter on a country-by-country basis. The test determines a limit, or ceiling, on the book value of oil and gas properties. That limit is basically the after tax present value of the future net cash flows from proved crude oil and natural gas reserves, as adjusted for asset retirement obligations and the effect of cash flow hedges. This ceiling is compared to the net book value of the oil and gas properties reduced by any related net deferred income tax liability. If the net book value reduced by the related deferred income taxes exceeds the ceiling, an impairment or non-cash writedown is required. A ceiling test impairment could cause Forest to record a significant non-cash loss for a particular period; however, future DD&A expense would be reduced thereafter.

In countries or areas where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs, and other costs incurred during the exploration phase remain capitalized as unproved property costs until proved reserves have been established or until exploration activities cease. 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.

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.

In general, the application of the full cost method of accounting results in higher capitalized costs and higher depletion rates compared to the successful efforts method.

The full cost method is used to account for our oil and gas exploration and development activities, because we believe it appropriately reports the costs of our exploration programs as part of an overall investment in discovering and developing proved reserves.

Impact of Recently Issued Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") SFAS No. 123(R), *Share-Based Payment* ("SFAS 123(R)"), which is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*. SFAS 123(R) is effective for public companies for interim or annual periods beginning after December 15, 2005, supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and amends SFAS No. 95, *Statement of Cash Flows*. SFAS 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values, beginning with the first interim or annual period after December 15, 2005, with early adoption encouraged. The pro forma disclosures previously permitted under SFAS No. 123 will no longer be an alternative to financial statement recognition. SFAS 123(R) also requires the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as currently required. This requirement may serve to reduce Forest's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future.

We are required to adopt SFAS 123(R) in the first quarter of 2006. Under SFAS 123(R), we must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost, and the transition method to be used at date of adoption. The transition methods include prospective and retroactive adoption options. Under the retroactive options, prior periods may be restated either as of the beginning of the year of adoption or for all periods presented. The prospective method requires that compensation expense be recorded for all unvested stock options and restricted stock at the beginning of the first quarter of adoption of SFAS 123(R); the retroactive methods would record compensation expense for all unvested stock options and restricted stock beginning with the first period restated. We have elected to adopt SFAS 123(R) using the prospective transition method and estimate that we will record approximately $3 million in additional compensation expense in 2006 related to unvested outstanding stock options. This estimate is based on the number of stock options outstanding at December 31, 2005 as well as an estimated overhead capitalization rate of approximately 40%, each of which are subject to change.

Forest also has an employee stock purchase plan (the "ESPP") that allows eligible employees to purchase annually Forest's Common Stock at a discount. The provisions of SFAS 123(R) will cause the ESPP to be accounted for as a compensatory plan. However, the change in accounting for the ESPP is not expected to have a material impact on Forest's financial position, future results of operations, or liquidity. Historically, the ESPP compensatory amounts that are required to be recorded under SFAS 123(R) have been nominal.

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.

Hedging Program

In order to reduce the impact of fluctuations in prices on our revenues, or to protect the economics of property acquisitions, we make use of an oil and gas hedging strategy. Under our hedging strategy, we enter into commodity swaps, collars, and other financial instruments with counterparties who, in general, are participants in our credit facilities. 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. Hedging arrangements covered approximately half of our consolidated production, on an equivalent basis, during each of the years ended December 31, 2005, 2004, and 2003. We do not enter into derivative instruments for trading purposes.

Swaps

In a typical commodity swap agreement, we receive the difference between a fixed price per unit of production and a price based on an agreed upon published, third-party index if the index price is lower than the fixed price. If the index price is higher, we pay the difference. By entering into swap agreements, we effectively fix the price that we will receive in the future for the hedged production. Our current swaps are settled in cash on a monthly basis. As of December 31, 2005, we had entered into the following swaps:

	Swaps					
	Natural Gas (NYMEX HH)			Oil (NYMEX WTI)		
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Fair Value (In Thousands)	Barrels Per Day	Weighted Average Hedged Price per Bbl	Fair Value (In Thousands)
First Quarter of 2006	50.0	$6.02	$(23,872)	4,000	$31.58	$(10,845)
Second Quarter 2006	50.0	6.02	(19,297)	4,000	31.58	(11,235)
Third Quarter 2006	50.0	6.02	(19,660)	4,000	31.58	(11,447)
Fourth Quarter 2006	50.0	6.02	(21,966)	4,000	31.58	(11,421)

In connection with the Spin-off and subsequent Merger transactions completed on March 2, 2006, three natural gas swaps included in the above table covering 40 Bbtus per day at an average fixed price of $6.15 were assigned to and assumed by Mariner. See Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operation," above, and Note 2 to the Consolidated Financial Statements for a discussion of the Spin-off.

Collars

Forest also enters 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.

	Costless Collars					
	Natural Gas (NYMEX HH)			Oil (NYMEX WTI)		
	Bbtu Per Day	Weighted Average Hedged Floor and Ceiling Price per MMBtu	Fair Value (In Thousands)	Barrels Per Day	Weighted Average Hedged Floor and Ceiling Price per Bbl	Fair Value (In Thousands)
First Quarter of 2006	50.0	$7.43/11.88	$(2,638)	5,500	$46.73/65.87	$(1,483)
Second Quarter 2006	50.0	7.43/11.88	(1,614)	5,500	46.73/65.87	(2,160)
Third Quarter 2006	50.0	7.43/11.88	(2,674)	5,500	46.73/65.87	(2,605)
Fourth Quarter 2006	50.0	7.43/11.88	(5,011)	5,500	46.73/65.87	(2,809)

The fair value of our hedges based on the futures prices quoted on December 31, 2005 was a net liability of approximately $150.7 million.

The following table reconciles the changes that occurred in the fair values of our open derivative contracts during 2005, beginning with the fair value of our commodity contracts on December 31, 2004, less the decrease in fair value during the period and the fair value of commodity contracts acquired in connection with the business combinations, plus the contract losses settled and recognized during the period.

	Fair Value of Derivative Contracts
	(In Thousands)
Unrealized losses on contracts as of December 31, 2004	$ (90,249)
Net decrease in fair value	(275,947)
Unrealized loss of acquired contracts	(6,373)
Net contract losses recognized	221,832
Unrealized losses on contracts of as December 31, 2005	$(150,737)

Long-Term Sales Contracts

A portion of Canadian Forest's natural gas production is sold in a joint venture with other producers (the "Canadian Netback Pool"). The Canadian Netback Pool's resale markets are comprised of market based and fixed price contracts. Canadian Forest's contractual obligation to deliver natural gas production volumes to these contracts extends through 2011. Canadian Forest's average daily production sold through the Canadian Netback Pool represented approximately 5.5% of Forest's total average daily production in 2005. Canadian Forest supplied 46% of the Canadian Netback Pool sales quantity in 2005, and it is estimated that Canadian Forest will supply 54% of the Canadian Netback Pool quantity in the 2006 contract year. We expect that Canadian Forest's pro rata obligations as a gas producer will increase in 2006 and future years. At December 31, 2005, the weighted average price paid under the resale contracts was approximately 76% of market value based on the closing AECO prices on that date. To the extent the Canadian Netback Pool's supply is insufficient to meet the delivery obligations under the resale contracts, as is currently the case, the Canadian Netback Pool must make up the shortfall by purchasing spot market gas at prices that currently exceed the prices paid under the resale contracts. This shortfall could increase if individual producers were to default on their supply obligations owed to the Canadian Netback Pool. See Note 10 to the Consolidated Financial Statements for more information.

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 United States dollar-denominated, as have cash proceeds related to property sales and farmout arrangements. Substantially all of our Canadian revenues and costs are denominated in Canadian dollars. While the value of the Canadian dollar does fluctuate in relation to the U.S. dollar, we believe that any currency risk associated with our Canadian operations would not have a material impact on our results of operations.

Interest Rate Risk

The following table presents principal amounts and related interest rates by year of maturity for Forest's debt obligations at December 31, 2005:

	2008	2009	2011	2014	Total	Fair Value
	(Dollar Amounts in Thousands)					
Bank credit facilities:						
Variable rate	$ —	153,806	—	—	153,806	153,806
Average interest rate(1)	—	5.29%	—	—	5.29%	—
Long-term debt:						
Fixed rate	$265,000	—	285,000	150,000	700,000	743,251
Coupon interest rate	8.00%	—	8.00%	7.75%	7.95%	—
Effective interest rate(2)	7.13%	—	7.71%	6.56%	7.24%	—

(1) As of December 31, 2005.

(2) The effective interest rate on the 8% Senior Notes due 2008, the 8% Senior Notes due 2011, and the 7¾% Senior Notes due 2014 is reduced from the coupon rate as a result of amortization of gains related to the termination of related interest rate swaps.

Item 8. Financial Statements and Supplementary Data.

Information concerning this Item begins on the following page.

Report of Independent Registered Public Accounting Firm

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, 2005 and 2004, 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, 2005. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the 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, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

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 No. 143.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Forest Oil Corporation's internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 13, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Denver, Colorado
March 13, 2006

FOREST OIL CORPORATION

CONSOLIDATED BALANCE SHEETS

(In Thousands Except Share Data)

	December 31, 2005	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,231	55,251
Accounts receivable	178,124	151,927
Derivative instruments	941	8,913
Current deferred tax asset	77,346	38,321
Other current assets	52,283	29,056
Total current assets	315,925	283,468
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of $3,059,031 and $2,701,402	2,898,774	2,500,160
Unproved	275,684	209,604
Net oil and gas properties	3,174,458	2,709,764
Other property and equipment, net of accumulated depreciation and amortization of $32,527 and $28,797	25,560	11,354
Net property and equipment	3,200,018	2,721,118
Goodwill	87,072	68,560
Other assets	42,531	49,359
	$3,645,546	3,122,505
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 312,076	202,537
Accrued interest	4,260	4,292
Derivative instruments	151,678	80,523
Asset retirement obligations	33,329	25,452
Other current liabilities	21,573	10,811
Total current liabilities	522,916	323,615
Long-term debt	884,807	888,819
Asset retirement obligations	178,225	184,724
Derivative instruments	—	20,890
Other liabilities	45,691	35,785
Deferred income taxes	329,385	196,525
Total liabilities	1,961,024	1,650,358
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock, none issued and outstanding	—	—
Common stock, 64,548,229 and 61,595,024 shares issued and outstanding	6,455	6,159
Capital surplus	1,555,347	1,447,007
Deferred stock based compensation	(26,245)	(2,640)
Retained earnings	217,293	66,007
Accumulated other comprehensive (loss) income	(18,220)	6,780
Treasury stock, at cost, 1,861,143 and 1,901,807 shares held	(50,108)	(51,166)
Total shareholders' equity	1,684,522	1,472,147
	$3,645,546	3,122,505

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands Except Per Share Amounts)		
Revenue:			
Oil and gas sales:			
Natural gas	$ 647,936	573,342	439,700
Oil, condensate, and natural gas liquids	414,581	336,438	215,493
Total oil and gas sales	1,062,517	909,780	655,193
Marketing, processing, and other	9,528	3,118	1,985
Total revenue	1,072,045	912,898	657,178
Operating expenses:			
Lease operating expenses	199,761	189,161	124,482
Production and property taxes	42,615	32,241	19,929
Transportation costs	19,499	16,792	9,759
General and administrative	43,703	32,145	36,322
Depreciation and depletion	368,679	354,092	234,822
Accretion of asset retirement obligations	17,317	17,251	13,785
Impairment and other	11,132	12,929	16,910
Total operating expenses	702,706	654,611	456,009
Earnings from operations	369,339	258,287	201,169
Other income and expense:			
Interest expense	61,403	57,844	49,341
Unrealized losses (gains) on derivative instruments, net	21,373	1,088	(451)
Realized losses (gains) on derivative instruments, net	35,390	(336)	68
Other expense (income), net	6,247	(2,179)	7,347
Total other income and expense	124,413	56,417	56,305
Earnings before income taxes, discontinued operations, and cumulative effect of change in accounting principle	244,926	201,870	144,864
Income tax expense:			
Current	3,498	2,960	693
Deferred	89,860	75,784	53,943
Total income tax expense	93,358	78,744	54,636
Earnings from continuing operations	151,568	123,126	90,228
Loss from discontinued operations, net of tax	—	(575)	(7,731)
Cumulative effect of change in accounting principle, net of tax	—	—	5,854
Net earnings	$ 151,568	122,551	88,351
Basic earnings per common share:			
Earnings from continuing operations	$ 2.47	2.16	1.82
Loss from discontinued operations, net of tax	—	(.01)	(.15)
Cumulative effect of change in accounting principle, net of tax	—	—	.12
Basic earnings per common share	$ 2.47	2.15	1.79
Diluted earnings per common share:			
Earnings from continuing operations	$ 2.41	2.12	1.79
Loss from discontinued operations, net of tax	—	(.01)	(.15)
Cumulative effect of change in accounting principle, net of tax	—	—	.11
Diluted earnings per common share	$ 2.41	2.11	1.75

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Capital Surplus	Deferred Stock Based Compensation	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive (Loss) Income	Treasury Stock	Total Shareholders' Equity
					(In Thousands)			
Balances at January 1, 2003	49,126	$4,913	1,159,269	—	(144,548)	(41,887)	(56,536)	921,211
Common stock issued, net of offering costs	6,023	602	132,982	—	—	—	—	133,584
Exercise of warrants to purchase 1,573 shares of common stock	2	—	33	—	—	—	—	33
Exercise of stock options	462	46	7,386	—	(298)	—	666	7,800
Tax benefit of stock options exercised	—	—	1,014	—	—	—	—	1,014
Employee stock purchase plan	21	2	422	—	—	—	—	424
Retirement of 1,583 shares in lieu of taxes on restricted stock award	—	—	(44)	—	—	—	—	(44)
Other	(2)	—	1,278	—	—	—	—	1,278
Comprehensive earnings:								
Net earnings	—	—	—	—	88,351	—	—	88,351
Unrealized gain on market value of investment, net of tax	—	—	—	—	—	481	—	481
Unrealized loss on effective derivative instruments, net of tax	—	—	—	—	—	(17,076)	—	(17,076)
Increase in unfunded pension liability, net of tax	—	—	—	—	—	(534)	—	(534)
Foreign currency translation	—	—	—	—	—	49,276	—	49,276
Total comprehensive earnings								120,498
Balances at December 31, 2003	55,632	5,563	1,302,340	—	(56,495)	(9,740)	(55,870)	1,185,798
Common stock issued, net of offering costs	5,030	503	116,585	—	—	—	—	117,088
Exercise of warrants to purchase 162,901 shares of common stock	163	16	3,093	—	—	—	—	3,109
Exercise of stock options	748	74	17,297	—	(320)	—	2,147	19,198
Tax benefit of stock options exercised	—	—	2,168	—	—	—	—	2,168
Employee stock purchase plan	22	3	507	—	—	—	—	510
Retirement of 501 shares in lieu of taxes on restricted stock award	—	—	—	—	—	—	(15)	(15)
Restricted stock issued	—	—	—	(2,843)	271	—	2,572	—
Amortization of deferred stock compensation, net of forfeitures and other	—	—	—	203	—	—	—	203
Tax benefit of acquired net operating losses	—	—	5,283	—	—	—	—	5,283
Other	—	—	(266)	—	—	—	—	(266)
Comprehensive earnings:								
Net earnings	—	—	—	—	122,551	—	—	122,551
Unrealized loss on effective derivative instruments, net of tax	—	—	—	—	—	(18,269)	—	(18,269)
Decrease in unfunded pension liability, net of tax	—	—	—	—	—	5,565	—	5,565
Foreign currency translation	—	—	—	—	—	29,224	—	29,224
Total comprehensive earnings								139,071
Balances at December 31, 2004	61,595	6,159	1,447,007	(2,640)	66,007	6,780	(51,166)	1,472,147

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (Continued)

	Common Stock		Capital Surplus	Deferred Stock Based Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Shareholders' Equity
					(In Thousands)			
Balances at December 31, 2004	61,595	6,159	1,447,007	(2,640)	66,007	6,780	(51,166)	1,472,147
Exercise of warrants to purchase 1,358,350 shares of common stock	1,358	137	14,248	—	—	—	—	14,385
Exercise of stock options	1,040	104	27,624	—	(376)	—	1,006	28,358
Tax benefit of stock options exercised	—	—	4,587	—	—	—	—	4,587
Employee stock purchase plan	19	1	633	—	—	—	—	634
Restricted stock issued, net of forfeitures	536	54	24,640	(24,840)	94	—	52	—
Amortization of deferred stock compensation, net of forfeitures and other	—	—	—	1,235	—	—	—	1,235
Tax benefit of acquired net operating losses	—	—	36,608	—	—	—	—	36,608
Comprehensive earnings:								
Net earnings	—	—	—	—	151,568	—	—	151,568
Unrealized loss on effective derivative instruments, net of tax	—	—	—	—	—	(36,301)	—	(36,301)
Increase in unfunded pension liability, net of tax	—	—	—	—	—	(210)	—	(210)
Foreign currency translation	—	—	—	—	—	11,511	—	11,511
Total comprehensive earnings								126,568
Balances at December 31, 2005	64,548	$6,455	1,555,347	(26,245)	217,293	(18,220)	(50,108)	1,684,522

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Operating activities:			
Net earnings	$ 151,568	122,551	88,351
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation and depletion	368,679	354,092	236,148
Accretion of asset retirement obligations	17,317	17,251	13,785
Impairments	2,924	6,261	16,910
Unrealized loss (gain) on derivative instruments, net	21,373	1,088	(451)
Cash settlement of deferred derivative losses	(15,204)	—	—
Cash settlements on derivatives acquired in business combinations	14,704	8,833	—
Deferred income tax expense	89,860	76,506	61,730
Other, net	2,374	(9,155)	163
Changes in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	(15,350)	32,754	(34,388)
Other current assets	(25,858)	(7,610)	6,281
Accounts payable	9,528	(43,456)	22,204
Accrued interest and other current liabilities	6,650	8,898	(28,749)
Net cash provided by operating activities	628,565	568,013	381,984
Investing activities:			
Acquisitions of subsidiaries	(196,645)	(223,834)	(82,160)
Capital expenditures for property and equipment:			
Exploration, development and other acquisition costs	(483,329)	(317,166)	(583,332)
Other fixed assets	(10,743)	(2,829)	(2,251)
Proceeds from sale of assets	24,046	97,933	14,445
Sale of goodwill and contract value	—	8,493	—
Other, net	(4,559)	(18,498)	(5,883)
Net cash used by investing activities	(671,230)	(455,901)	(659,181)
Financing activities:			
Proceeds from bank borrowings	2,351,741	2,025,074	865,511
Repayments of bank borrowings	(2,350,000)	(2,165,646)	(668,000)
Repayments of bank debt assumed in acquisitions	(35,000)	(66,354)	—
Proceeds from the exercise of options and warrants and from employee stock purchase plan	43,377	22,894	8,257
Issuance of 8% senior notes, net of issuance costs	—	133,312	—
Redemption of 9½% senior notes	—	(126,971)	—
Proceeds of common stock offerings, net of offering costs	—	117,088	318,216
Redemption and repurchase of 10½% senior subordinated notes	—	—	(69,441)
Repurchase and retirement of common stock	—	—	(184,632)
Cash settlements on derivatives acquired in business combinations	(14,704)	(8,833)	—
Other, net	(10)	1,167	4,638
Net cash (used) provided by financing activities	(4,596)	(68,269)	274,549
Effect of exchange rate changes on cash	(759)	(101)	991
Net (decrease) increase in cash and cash equivalents	(48,020)	43,742	(1,657)
Cash and cash equivalents at beginning of year	55,251	11,509	13,166
Cash and cash equivalents at end of year	$ 7,231	55,251	11,509
Cash paid during the year for:			
Interest	$ 66,140	64,687	55,632
Income taxes	7,900	3,790	1,968

See accompanying Notes to Consolidated Financial Statements.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Description of the Business

Forest Oil Corporation is an independent oil and gas company engaged in the acquisition, exploration, development, and production of natural gas and liquids primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. The Company is active in several of the major exploration and producing areas in the United States and in Canada, and has exploratory interests in various other foreign countries.

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of Forest Oil Corporation and its consolidated subsidiaries (collectively, "Forest" or the "Company"). Significant intercompany balances and transactions are eliminated. The Company consolidates all subsidiaries in which it controls over 50% of the voting interests. Entities in which the Company does not have a direct or indirect majority voting interest are generally accounted for using the equity method. Under the equity method, the initial investment in the affiliated entity is recorded at cost and subsequently increased or reduced to reflect the Company's share of gains or losses or dividends received from the affiliate. The Company's share of the income or losses of the affiliate is included in the Company's reported net income.

Certain amounts in prior years' financial statements have been reclassified to conform to the 2005 financial statement presentation.

Assumptions, Judgments, and Estimates

In the course of preparing the consolidated financial statements, management makes various assumptions, judgments, and estimates to determine the reported amounts of assets, liabilities, revenue, and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts previously established.

The more significant areas requiring the use of assumptions, judgments, and estimates relate to volumes of oil and gas reserves used in calculating depletion, the amount of future net revenues used in computing the ceiling test limitations, and the amount of future capital costs and abandonment obligations used in such calculations. Assumptions, judgments, and estimates are also required in determining impairments of undeveloped properties, valuing deferred tax assets, and estimating fair values of derivative instruments.

Cash Equivalents

For purposes of the statements of cash flows, the Company considers all debt instruments with original maturities of three months or less to be cash equivalents.

Property and Equipment

The Company uses the full cost method of accounting for oil and gas properties. Separate cost centers are maintained for each country in which the Company has operations. During 2005, 2004, and

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

2003, the Company's primary oil and gas operations were conducted in the United States and Canada. 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) and the fair value of estimated future costs of site restoration, dismantlement, and abandonment activities are capitalized. Interest costs related to unusually significant unproved properties which are under development are also capitalized to oil and gas properties. During 2005, the Company capitalized approximately $.9 million of interest expense related to its Buffalo Wallow project where a significant amount of value was attributed to undeveloped properties. No interest was capitalized in 2004 or 2003.

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

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter. The ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for each cost center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and gas reserves using current prices, including the effects of derivative instruments but excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, and a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax basis of oil and gas properties. There were no provisions for impairment of proved oil and gas properties in 2005, 2004, or 2003.

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

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, as adjusted for future development costs and asset retirement obligations, are amortized over the total estimated proved reserves. Furniture and fixtures, leasehold improvements, computer hardware and software, and other equipment are depreciated on the straight-line or declining balance method, based upon estimated useful lives of the assets ranging from three to 12 years.

Asset Retirement Obligations

Effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). 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, with a corresponding increase in the carrying amount of the

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

related long-lived asset. Prior to 2003, the Company recorded estimated costs of future abandonment liabilities, net of estimated salvage values, as part of its provision for depreciation and depletion for oil and gas properties, without recording a separate liability for such amounts. The Company's asset retirement obligations consist of costs related to the plugging of wells, the removal of facilities and equipment, and site restoration on oil and gas properties.

Upon adoption of SFAS No. 143 in the first quarter of 2003, the Company recorded an increase to net property and equipment of $165.4 million, an asset retirement obligation liability of $156.0 million, and an after tax credit of $5.9 million for the cumulative effect of the change in accounting principle related to the depreciation, depletion, and accretion amounts that would have been reported had the asset retirement obligations been recorded when incurred. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period. Capitalized costs are depleted as a component of the full cost pool using the units-of-production method.

The following table summarizes the activities for the Company's asset retirement obligations for the years ended December 31, 2005 and 2004:

	Year Ended December 31,	
	2005	2004
	(In Thousands)	
Asset retirement obligations at beginning of period	$210,176	211,432
Accretion expense	17,317	17,251
Liabilities incurred	4,739	21,794
Liabilities settled	(32,711)	(33,797)
Liabilities assumed	705	10,556
Revisions of estimated liabilities	10,890	(18,285)
Impact of foreign currency exchange rate	438	1,225
Asset retirement obligations at end of period	211,554	210,176
Less: current asset retirement obligations	33,329	25,452
Long-term asset retirement obligations	$178,225	184,724

Revisions of estimated liabilities in 2005 include the effects of accelerating the timing and cost of abandoning facilities damaged by hurricanes in the third quarter of 2005. Subsequent to December 31, 2005, on March 2, 2006 the Company completed the spin-off of its offshore Gulf of Mexico operations (see Note 2). As of December 31, 2005, asset retirement obligations associated with the offshore Gulf of Mexico operations which were part of the spin-off transaction, as discussed in Note 2, were approximately $148 million.

Financial Instruments

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents and accounts receivable. The Company's cash equivalents are cash investments that are placed with major financial institutions. The Company attempts to minimize credit risk exposure to purchasers of the Company's oil and natural gas through formal credit policies, monitoring procedures, and letters of credit when considered necessary.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

The Company used various assumptions and methods in estimating fair value disclosures for financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short maturity of these instruments. The carrying amount of the Company's credit facilities approximated fair value because the interest rates on the credit facilities are variable. The fair values of senior notes were estimated based on quoted market prices, if available, or quoted market prices of comparable instruments. The fair values of derivative instruments were estimated based on discounted future net cash flows and option pricing models.

	December 31, 2005		December 31, 2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In Thousands)			
Long-term debt:				
8.00% Senior notes due 2008	$270,408	276,263	272,611	292,494
8.00% Senior notes due 2011	297,742	311,363	299,871	325,612
7.75% Senior notes due 2014	162,851	155,625	164,337	163,125
Derivative instruments	150,737	150,737	90,249	90,249

For additional disclosures regarding the Company's long-term debt and derivative instruments, see Notes 4 and 8, respectively.

Oil and Gas Sales

Natural gas revenues are recorded on the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company's net interest. The Company records its entitled share of revenues based on estimated production volumes. Subsequently, these estimated volumes are adjusted to reflect actual volumes that are supported by third party pipeline statements or cash receipts. Since there is a ready market for natural gas, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer.

Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess of the Company's share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2005 and 2004, the Company had net gas imbalance receivables of $4.0 million and $2.1 million, respectively.

Oil revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title is transferred.

In 2004, sales to four purchasers were approximately 15%, 11%, 11%, and 11% of total revenue, and in 2003, sales to three purchasers were approximately 15%, 10%, and 10% of total revenue.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Accounts Receivable

The components of accounts receivable include the following:

	December 31,	
	2005	2004
	(In Thousands)	
Oil and natural gas sales	$136,973	122,923
Joint interest billings	38,595	21,599
Other	4,103	8,780
Allowance for doubtful accounts	(1,547)	(1,375)
	$178,124	151,927

Marketing, Processing, and Other

Marketing, processing, and other primarily consists of marketing fees earned from third party marketing arrangements and fees earned attributable to volumes processed on behalf of third parties through Company-owned gas processing plants.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred tax liabilities and assets for the expected future tax consequences of temporary differences between financial accounting bases and tax bases of assets and liabilities. The tax benefits of tax loss carryforwards and other deferred taxes are recorded as an asset to the extent that management assesses the utilization of such assets to be more likely than not. When the future utilization of some portion of the deferred tax asset is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded deferred tax assets. Management believes that it could implement tax planning strategies to prevent certain of these carryforwards from expiring.

Foreign Currency Translation

The functional currency of Canadian Forest Oil Ltd. (“Canadian Forest”), the Company’s wholly owned Canadian subsidiary, is the Canadian dollar. Assets and liabilities related to Canadian Forest are generally translated at current exchange rates, and related translation adjustments are generally reported as a component of shareholders’ equity in accumulated other comprehensive income (loss). Statement of operations accounts are translated at the average exchange rates during the period.

During 2004, Forest realized approximately $4.7 million of foreign currency exchange gains in connection with the repayment of intercompany loans. The $4.7 million gain is included in other expense (income), net in the Consolidated Statements of Operations.

Earnings per Share

Basic earnings per share is computed by dividing net earnings attributable to common stock by the weighted average number of common shares outstanding during each period, excluding treasury shares.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Diluted earnings per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of convertible preferred stock, stock options, unvested restricted stock awards and warrants.

The following sets forth the calculation of basic and diluted earnings per share for the years ended December 31:

	2005	2004	2003
	(In Thousands Except Per Share Amounts)		
Earnings from continuing operations	$151,568	123,126	90,228
Weighted average common shares outstanding during the period	61,405	56,925	49,450
Add dilutive effects of stock options and unvested restricted stock grants	1,145	384	218
Add dilutive effects of warrants	328	780	685
Weighted average common shares outstanding including the effects of dilutive securities	62,878	58,089	50,353
Basic earnings from continuing operations	$ 2.47	2.16	1.82
Diluted earnings from continuing operations	2.41	2.12	1.79

Stock Based Compensation

The Company applied APB Opinion 25, *Accounting for Stock Issued to Employees*, and related Interpretations in accounting for its stock-based compensation plans through December 31, 2005. Accordingly, no compensation cost was recognized for options granted at a price equal to or greater than the fair market value of the common stock. Compensation cost was recognized over the vesting period of options granted at a price less than the fair market value of the common stock at the date of the grant. No compensation cost was recognized for stock purchase rights that qualify under Section 423 of the Internal Revenue Code as a non-compensatory plan. Had compensation cost for the Company's stock-based compensation plans been determined using the fair value of the options at the grant date as prescribed by Statement of Financial Accounting Standards No. 123, *Accounting for*

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Stock-Based Compensation, the Company's pro forma net earnings and earnings per common share would have been as follows:

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands Except Per Share Data)		
Net earnings, as reported	$151,568	122,551	88,351
Add: Stock-based employee compensation included in reported net income, net of tax	457	92	479
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	(2,709)	(3,155)	(5,353)
Pro forma net earnings	$149,316	119,488	83,477
Basic earnings per common share:			
As reported	$ 2.47	2.15	1.79
Pro forma	2.43	2.10	1.69
Diluted earnings per common share:			
As reported	$ 2.41	2.11	1.75
Pro forma	2.37	2.06	1.66

Treasury Stock

The Company accounts for treasury stock acquisitions using the cost method. For reissuance of treasury stock, to the extent that the reissuance price is more than the cost, the excess is recorded as an increase to capital surplus. If the reissuance price is less than the cost, the difference is also recorded to capital surplus to the extent there is a cumulative treasury stock paid in capital balance. Once the cumulative balance is reduced to zero, any remaining difference resulting from the sale of treasury stock below cost is recorded to retained earnings.

Goodwill

The Company accounts for goodwill in accordance with SFAS No. 142, *"Goodwill and other Intangible Assets,"* and is required to make an annual impairment assessment in lieu of periodic amortization. The impairment assessment requires the Company to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. Although the Company bases its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, continued weakening of the U.S. dollar or depressed natural gas, NGLs, and crude oil prices could lead to an impairment of goodwill in future periods.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Comprehensive Earnings (Loss)

Comprehensive earnings (loss) is a term used to refer to net earnings (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under generally accepted accounting principles are reported as separate components of shareholders' equity instead of net earnings (loss). Items included in the Company's other comprehensive income (loss) for the years ended December 31, 2005, 2004, and 2003 are foreign currency gains (losses) related to the translation of the assets and liabilities of the Company's Canadian operations; changes in the unfunded pension liability; unrealized gains (losses) related to the change in fair value of securities available for sale; and unrealized gains (losses) related to the changes in fair value of derivative instruments designated as cash flow hedges.

The components of comprehensive earnings (loss) for the years ended December 31, 2005, 2004, and 2003 are as follows:

	Foreign Currency Translation	Unfunded Pension Liability[1]	Unrealized Gain (Loss) on Securities Available for Sale[1]	Unrealized Gain (Loss) on Derivative Instruments, Net[1]	Accumulated Other Comprehensive Income (Loss)
			(In Thousands)		
Balance at January 1, 2003	$(10,598)	(13,451)	(481)	(17,357)	(41,887)
2003 activity	49,276	(534)	481	(17,076)	32,147
Balance at December 31, 2003	38,678	(13,985)	—	(34,433)	(9,740)
2004 activity	29,224	5,565	—	(18,269)	16,520
Balance at December 31, 2004	67,902	(8,420)	—	(52,702)	6,780
2005 activity	11,511	(210)	—	(36,301)	(25,000)
Balance at December 31, 2005	$ 79,413	(8,630)	—	(89,003)	(18,220)

(1) Net of tax.

The table below sets forth, for the periods presented, changes in the Company's unrealized losses on derivative instruments included as a component of comprehensive earnings.

	Years Ended December 31, 2005	2004	2003
	(In Thousands)		
Unrealized derivative loss in comprehensive earnings, beginning of period	$ 85,003	55,537	27,995
Change in fair value	291,276	146,595	100,405
Reclassification of net losses to earnings	(186,442)	(117,129)	(72,863)
Discontinuance of hedge accounting	(46,284)	—	—
	143,553	85,003	55,537
Related income tax effect	(54,550)	(32,301)	(21,104)
Unrealized derivative loss in comprehensive earnings, end of period	$ 89,003	52,702	34,433

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Impact of Recently Issued Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") SFAS No. 123, *Share-Based Payment* ("SFAS 123(R)"), which is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*. SFAS 123(R) is effective for public companies for interim or annual periods beginning after December 15, 2005, supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and amends SFAS No. 95, *Statement of Cash Flows*. SFAS 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values, beginning with the first interim or annual period after December 15, 2005, with early adoption encouraged. The pro forma disclosures previously permitted under SFAS No. 123 will no longer be an alternative to financial statement recognition. SFAS 123(R) also requires the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as currently required. This requirement may serve to reduce Forest's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future.

Forest was required to adopt SFAS 123(R) in the first quarter of 2006. Under SFAS 123(R), Forest must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost, and the transition method to be used at date of adoption. The transition methods include prospective and retroactive adoption options. Under the retroactive options, prior periods may be restated either as of the beginning of the year of adoption or for all periods presented. The prospective method requires that compensation expense be recorded for all unvested stock options and restricted stock at the beginning of the first quarter of adoption of SFAS 123(R); the retroactive methods would record compensation expense for all unvested stock options and restricted stock beginning with the first period restated. Forest elected to adopt SFAS 123(R) using the prospective transition method and Forest estimates it will record approximately $3 million in additional compensation expense in 2006 related to unvested outstanding stock options. This estimate is based on the number of stock options outstanding at December 31, 2005 as well as an estimated overhead capitalization rate of approximately 40%, each of which is subject to change.

Forest also has an employee stock purchase plan that allows eligible employees to purchase annually Forest's common stock at a discount. The provisions of SFAS 123(R) will cause this plan to be accounted for as a compensatory plan. However, the change in accounting for this plan is not expected to have a material impact on Forest's financial position, future results of operations, or liquidity. Historically, the compensatory amounts associated with this plan that would have been recorded under SFAS 123(R) have been nominal.

(2) ACQUISITIONS AND DIVESTITURES:

Acquisitions

Cotton Valley Acquisition—Pending

On February 13, 2006, Forest announced its plans to acquire assets located primarily in the Cotton Valley trend in East Texas. Forest agreed to pay approximately $255 million, subject to customary adjustments, for properties with an estimated 110 Bcfe of proved reserves (unaudited) and production

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

that averaged 13 MMcfe per day (unaudited) in January 2006. In addition to the reserves and production, Forest will also gain approximately 26,000 net acres (unaudited) in the fields, of which approximately 14,000 net acres (unaudited) are undeveloped. The transaction is expected to close on March 31, 2006 and is subject to customary closing conditions.

Buffalo Wallow Acquisition

On April 1, 2005, Forest purchased a private company whose primary assets are located in the Buffalo Wallow field in Texas and include approximately 33,000 gross acres (unaudited) located primarily in Hemphill and Wheeler Counties, Texas (“the Buffalo Wallow Acquisition”). At the time of acquisition, the Buffalo Wallow Acquisition also included approximately 120 Bcfe of estimated proved reserves (unaudited). The purchase price was allocated to assets and liabilities, adjusted for tax effects, based on their estimated fair values at the date of acquisition. The acquisition was accounted for using the purchase method of accounting and has been included in the consolidated financial statements of Forest since the date of acquisition.

The net cash consideration paid for the Buffalo Wallow Acquisition was allocated as follows:

	Purchase Price Allocation
	(In Thousands)
Current assets	$ 9,434
Oil and gas properties	305,005
Goodwill	22,959
Other assets	68
Current liabilities	(27,251)
Derivative liability—current	(6,373)
Long-term debt	(35,000)
Asset retirement obligations	(705)
Deferred income taxes	(71,492)
Net cash consideration	$196,645

Goodwill of $23.0 million has been recognized to the extent that cost exceeded the fair value of net assets acquired. Goodwill is not expected to be deductible for tax purposes. The goodwill was assigned to Forest’s Western business unit. The principal factors that contributed to the recognition of goodwill include the mix of complementary high-quality assets in one of our existing core areas, lower-risk exploitation opportunities, expected increased cash flow from operations available for investing activities, and opportunities for cost savings through administrative and operational synergies.

Acquisition of The Wiser Oil Company

In June 2004, the Company completed its acquisition of the common stock of The Wiser Oil Company (“Wiser”), which held oil and gas assets located in the Company’s Gulf Coast, Western U.S., and Canada business units (the “Wiser Acquisition”). The Wiser Acquisition provided potential for increased production, reserves, and undeveloped acreage as well as diversification in terms of both

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

current production and long-term growth opportunities. At the time the acquisition was closed, the net oil and gas reserves were estimated to be approximately 186 Bcfe (unaudited), of which 85% (unaudited) were classified as proved developed and the remaining amounts were classified as proved undeveloped. Average production from the Wiser properties at the time of acquisition was 64 MMcfe (unaudited) per day. The acquisition also included working capital and certain other financial assets and liabilities of Wiser. The purchase price was allocated to assets and liabilities, adjusted for tax effects, based on the fair values at the date of acquisition. The acquisition was accounted for using the purchase method of accounting and has been included in the consolidated financial statements of Forest since the date of acquisition.

The total cash purchase price, including transaction costs, of $171 million was allocated to the assets acquired and the liabilities assumed based on the estimated fair values set forth in the table below.

	Purchase Price Allocation
	(In Thousands)
Current assets	$ 24,432
Proved properties	301,103
Other plant and equipment assets	2,450
Undeveloped leasehold costs	45,803
Goodwill	64,109
Current liabilities	(37,872)
Derivative liability—current	(8,028)
Long-term debt	(163,325)
Asset retirement obligations	(7,997)
Other liabilities	(3,489)
Deferred income taxes	(46,631)
Total cash consideration	$ 170,555

Goodwill of $64.1 million ($63.6 million before effects of foreign currency exchange) has been recognized to the extent that cost exceeded the fair value of net assets acquired. See Note 13 for the allocation of goodwill between operating segments. Goodwill is not expected to be deductible for tax purposes. The principal factor that contributed to the recognition of goodwill was opportunities for cost savings through administrative and operational synergies.

Other Acquisitions

Throughout 2005 and 2004, Forest made several other acquisitions of oil and gas properties for cash consideration totaling $8.5 million and $86.4 million, respectively. Total estimated proved reserves acquired in these other acquisitions totaled approximately 7 Bcfe (unaudited) and 63 Bcfe (unaudited) in 2005 and 2004, respectively.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

Divestitures

Spin-off and Merger of Offshore Gulf of Mexico Operations—Subsequent Event

On March 2, 2006, Forest completed the spin-off of its offshore Gulf of Mexico operations by means of a special stock dividend, which consisted of a pro rata spin-off (the "Spin-off") of all outstanding shares of Forest Energy Resources, Inc. ("FERI"), a total of 50,637,010 shares of common stock, to holders of record of Forest common stock, par value $.10 per share, as of the close of business on February 21, 2006. Immediately following the Spin-off, FERI was merged with a subsidiary of Mariner in a stock for stock transaction (the "Merger"). Mariner commenced trading on the New York Stock Exchange on March 3, 2006.

The Spin-off was completed without the payment of consideration by Forest shareholders and consisted of a special stock dividend of 0.8093 shares of FERI for each outstanding share of Forest common stock. The Merger was accomplished by the exchange of all issued and outstanding shares of FERI for shares of common stock of Mariner, with each whole share of FERI exchanged for one share of Mariner common stock.

The Spin-off is intended to be a tax-free transaction for federal income tax purposes. Prior to the Merger, as part of the Spin-off, FERI paid Forest an initial cash amount equal to approximately $176 million. The cash amount is subject to further adjustment to reflect an economic effective date for the transaction of July 1, 2005.

For the year ended December 31, 2005, the offshore Gulf of Mexico operations included in the Spin-off accounted for approximately 40% of the Company's total oil and gas production, 37% of the Company's consolidated oil and gas revenues, and 32% of the Company's lease operating expenses. If the Spin-off had occurred as of December 31, 2005, the Company would have reduce its oil and gas properties by approximately $1 billion, reduce its shareholders' equity by approximately $.5 billion, and reduce its asset retirement obligations by approximately $148 million.

Sale of ProMark

On March 1, 2004, the Company sold the assets and business operations of Producers Marketing, Ltd. ("ProMark") to Cinergy Canada, Inc. ("Cinergy") for $11.2 million CDN. Under the terms of the purchase and sale agreement, Cinergy will market natural gas (not already subject to prior contractual commitment) on behalf of Canadian Forest for five years through February 2009. Cinergy will also administer the netback pool formerly administered by ProMark. Forest could receive additional contingent payments over the next four years if Cinergy meets certain earnings goals with respect to the acquired business.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

As a result of the sale, ProMark's results of operations have been reported as discontinued operations in the accompanying financial statements. The components of loss from discontinued operations for the years ended December 31, 2004 and 2003 are as follows:

	Year Ended December 31, 2004	Year Ended December 31, 2003
	(In Thousands)	
Marketing revenue, net	$ 597	2,728
General and administrative expense	(280)	(1,921)
Interest expense	(2)	(59)
Other (expense) income	(166)	606
Depreciation	—	(1,325)
Current income tax (expense) benefit	(2)	27
Deferred income tax expense	(722)	(2,623)
Loss on sale of discontinued operations	—	(5,164)
Loss from discontinued operations, net of tax	$(575)	(7,731)

Other Divestitures

During 2005, Forest sold oil and gas properties with estimated proved reserves of approximately 15.0 Bcfe (unaudited), for total cash proceeds of approximately $24.0 million. During 2004, Forest disposed of properties with estimated proved reserves of approximately 85 Bcfe (unaudited), for total proceeds of approximately $97.9 million.

(3) PROPERTY AND EQUIPMENT:

Net property and equipment at December 31, 2005 and 2004 consists of the following:

	2005	2004
	(In Thousands)	
Oil and gas properties:		
Proved oil and gas properties	$ 5,957,805	5,201,562
Unproved properties not subject to depletion	275,684	209,604
Accumulated depletion	(3,059,031)	(2,701,402)
Net oil and gas properties	3,174,458	2,709,764
Other property and equipment:		
Furniture and fixtures, computer hardware and software, and other equipment	58,087	40,151
Accumulated depreciation and amortization	(32,527)	(28,797)
Net other property and equipment	25,560	11,354
Total net property and equipment	$ 3,200,018	2,721,118

(3) PROPERTY AND EQUIPMENT: (Continued)

The following table sets forth a summary of oil and gas property costs not being depleted at December 31, 2005, by the year in which such costs were incurred, and related transfers to proved, impairment charges, and sales:

	Total	2005	2004	2003	Prior
			(In Thousands)		
United States:					
Acquisition costs	$255,711	69,245	43,171	4,201	139,094
Exploration costs	441,363	42,061	12,272	14,650	372,380
Less transfers to proved	(522,825)	(16,843)	(14,649)	(9,862)	(481,471)
Total United States	174,249	94,463	40,794	8,989	30,003
Canada:					
Acquisition costs	40,666	4,580	14,281	—	21,805
Exploration costs	34,585	4,741	5,410	2,831	21,603
Less transfers to proved	(30,453)	(241)	(7,801)	(1,141)	(21,270)
Total Canada	44,798	9,080	11,890	1,690	22,138
International:					
Acquisition costs	11,897	—	—	22	11,875
Exploration costs	103,807	3,688	5,755	8,189	86,175
Less impairments	(45,890)	(4)	(3,020)	(5,194)	(37,672)
Less sales	(13,177)	—	—	(1,410)	(11,767)
Total International	56,637	3,684	2,735	1,607	48,611
Total	$275,684	107,227	55,419	12,286	100,752

Forest holds interests in various projects located outside North America. Costs related to these international interests of $56.6 million are not being depleted pending determination of the existence of estimated proved reserves. Forest's exploration project in South Africa accounts for the majority of the $56.6 million of international costs not being amortized. During 2004, Forest initiated a gas marketing program in South Africa seeking to negotiate with potential gas purchases of possible future South Africa natural gas production. Forest expects that substantially all unevaluated costs for this project will be classified as evaluated within the next five years. Of the $174.2 million of United States costs not being amortized, approximately $47.5 million relate to the Company's Buffalo Wallow area. Throughout 2005, the Company conducted drilling activities in this field and plans to continue such activities throughout 2006. In 2005, Forest recorded an impairment of $2.9 million primarily related to certain concessions in Romania. In 2004, Forest recorded an impairment of $4.0 million related primarily to concessions in Albania, Germany, and Italy. In 2003, Forest recorded an impairment of $16.9 million related primarily to concessions in Albania, Italy, Romania, Switzerland, and Tunisia. The Company anticipates that the majority of all the unproved costs in the table above will be classified as proved within the next five years.

(4) LONG-TERM DEBT:

Components of long-term debt are as follows:

	December 31, 2005				December 31, 2004			
	Principal	Unamortized Premium (Discount)	Other[3]	Total	Principal	Unamortized Premium (Discount)	Other[3]	Total
				(In Thousands)				
U.S. Credit Facility[1]	$ 97,000	—	—	97,000	152,000	—	—	152,000
Canadian Credit Facility[1]	56,806	—	—	56,806	—	—	—	—
8% Senior Notes Due 2008	265,000	(244)	5,652	270,408	265,000	(341)	7,952	272,611
8% Senior Notes Due 2011[2]	285,000	7,750	4,992	297,742	285,000	9,042	5,829	299,871
7¾% Senior Notes Due 2014	150,000	(1,990)	14,841	162,851	150,000	(2,228)	16,565	164,337
	$853,806	5,516	25,485	884,807	852,000	6,473	30,346	888,819

(1) In September 2004, Forest entered into amended and restated credit facilities totaling $600 million. As of March 3, 2006, the credit facilities consisted of a $500 million United States credit facility and a $100 million Canadian credit facility. The credit facilities mature in September 2009. Subject to the agreement of Forest and the applicable lenders, the size of the credit facilities may be increased by $200 million in the aggregate.

(2) In July 2004, Forest issued an additional $125 million in principal amount of 8% Senior Notes due 2011, at 107.75% of par, for proceeds of $133.3 million (net of related offering costs). Net proceeds from this offering were used to reduce the balance outstanding under Forest's U.S. credit facility.

(3) Represents the unamortized portion of gains realized upon termination of interest rate swaps that were accounted for as fair value hedges. The gains are being amortized as a reduction of interest expense over the terms of the note issues.

Bank Credit Facilities

The Company currently has 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 September 2009. Subject to the agreement of Forest and the applicable lenders, the size of the credit facilities may be increased by $200 million in the aggregate.

Availability under the credit facilities will be based either on certain financial covenants included in the credit facilities or on the loan value assigned to Forest's oil and gas properties. If Forest's corporate credit rating by Moody's is "Ba1" or higher and "BB+" or higher by S&P, the credit facilities may be governed by certain financial covenants. Alternatively, if Forest's corporate credit rating is "Ba2" or lower by Moody's or "BB" or lower by S&P, availability under the credit facilities will be governed by a borrowing base ("Global Borrowing Base"). Currently, the amount available under the credit facilities is determined by the Global Borrowing Base. Effective October 19, 2005, the credit facilities were amended to permit Forest to complete the Spin-off and the Global Borrowing Base was increased to $900 million. On March 2, 2006, concurrent with the completion of the Spin-off, the Global Borrowing Base was reduced to $600 million, with $500 million allocated to the U.S. credit facility and $100 million allocated to the Canadian facility.

(4) LONG-TERM DEBT: (Continued)

At December 31, 2005, there were outstanding borrowings of $97.0 million under the U.S. credit facility at a weighted average interest rate of 5.6%, and there were outstanding borrowings of $56.8 million under the Canadian credit facility at a weighted average interest rate of 4.8%. Forest also had used the credit facilities for approximately $6.9 million in letters of credit, leaving an unused borrowing amount under the Global Borrowing Base of approximately $439.3 million at December 31, 2005.

The determination of the Global Borrowing Base is made by the lenders taking into consideration the estimated value of Forest's oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. This process involves reviewing Forest's estimated proved reserves and their valuation. While the Global Borrowing Base is in effect, it is redetermined semi-annually, and the available borrowing amount could be increased or decreased as a result of such redeterminations. In addition, Forest and the lenders each have discretion at any time, but not more often than once during any calendar year, to have the Global Borrowing Base redetermined. A revision to Forest's reserves may prompt such a request on the part of the lenders, which could possibly result in a reduction in the Global Borrowing Base and availability under the credit facilities. As described above, in connection with the Spin-off, the Global Borrowing Base was reduced to $600 million. If outstanding borrowings under either of the credit facilities exceed the applicable portion of the Global Borrowing Base, Forest would be required to repay the excess amount within a prescribed period. If we are unable to pay the excess amount, it would cause an event of default.

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, mergers, and acquisitions. The credit facilities also include several financial covenants. Availability, interest rates, security requirements, and other terms of borrowing under the credit facilities will vary based on Forest's credit ratings and financial condition, as determined by certain financial tests. In particular, any time that availability is not determined by the Global Borrowing Base, the amount available and our ability to borrow under the credit facilities is determined by certain financial covenants. Also, even when availability is determined by the Global Borrowing Base, certain financial covenants may affect the amount available and Forest's ability to borrow amounts under the credit facilities.

The credit facilities include conditions linked to the Company's credit ratings. The fees and interest rates on the Company's commitments and loans and its collateral obligations are affected by its credit ratings. The Company's ability to raise funds and the cost of any financing activities may be affected by the Company's credit ratings at the time any such activities are conducted.

The credit facilities are collateralized by a portion of the Company's assets. The Company is required to mortgage, and grant a security interest in, 75% of the present value of its consolidated proved oil and gas properties. Forest also pledged the stock of several subsidiaries to the lenders to secure the credit facilities. Under certain circumstances, Forest could be obligated to pledge additional assets as collateral. If the Company's corporate credit ratings by Moody's and S&P improve and meet pre-established levels, the collateral requirements would not apply and, at the Company's request, the banks would release their liens and security interests on the Company's properties.

(4) LONG-TERM DEBT: (Continued)

8% Senior Notes Due 2008

In June 2001, Forest issued $200 million in principal amount of 8% Senior Notes due 2008 (the "8% Notes Due 2008") at par for proceeds of $199.5 million (net of related offering costs). In October 2001, Forest issued an additional $65 million in principal amount of 8% Notes Due 2008 at 99% of par for proceeds of $63.6 million (net of related offering costs).

8% Senior Notes Due 2011

In December 2001, Forest issued $160 million in principal amount of 8% Senior Notes due 2011 (the "8% Notes Due 2011") at par for proceeds of $157.5 million (net of related offering costs). In July 2004, Forest issued an additional $125 million in principal amount of 8% Senior Notes due 2011 at 107.75% of par for proceeds of $133.3 million (net of related offering costs).

7¾% Senior Notes Due 2014

In 2002, Forest issued $150 million in principal amount of 7¾% Senior Notes due 2014 (the "7¾% Notes") at 98.09% of par for proceeds of $146.8 million (net of related offering costs).

(5) INCOME TAXES:

The Company accounts for income taxes in accordance with the provisions of Statement of Financial Accounting Standards No. 109, *"Accounting for Income Taxes"* ("SFAS 109").

The provision for income taxes consist of the following for the periods presented:

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Current:			
Federal	$ 3,738	980	(7)
Foreign	238	297	248
State	(478)	1,683	452
	3,498	2,960	693
Deferred:			
Federal	55,608	60,776	48,798
Foreign	24,310	9,852	962
State, net	9,942	5,156	4,183
	89,860	75,784	53,943
	$93,358	78,744	54,636

(5) INCOME TAXES: (Continued)

Income from continuing operations before income taxes, discontinued operations, and cumulative effect of change in accounting principle consists of the following for the periods presented:

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands)		
U.S. federal	$168,024	174,398	144,721
Foreign	76,902	27,472	143
	$244,926	201,870	144,864

A reconciliation of income tax computed by applying the U.S. statutory federal income tax rate is as follows:

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Federal income tax at 35% of income before income taxes, discontinued operations, and cumulative effect of change in accounting principle	$85,724	70,655	50,702
State income taxes, net of federal income tax benefits	5,759	5,140	3,820
Change in the valuation allowance for deferred tax assets	(5,460)	1,029	925
Effect of differing tax rates in Canada	1,537	2,440	2,747
Effect of taxable dividends repatriated under Section 965 of the I.R.C.	4,275	—	3,881
Effect of Canadian statutory rate reductions	(3,129)	(2,388)	(7,332)
Other	4,652	1,868	(107)
Total income tax expense	$93,358	78,744	54,636

The Company's current income tax expense in 2005 primarily resulted from federal and state tax imposed on a dividend received from the Company's Canadian subsidiary. The Company elected to repatriate these funds to take advantage of a special one-time dividends received deduction on the repatriation of certain foreign earnings introduced by the American Jobs Creation Act of 2004. The Company will invest 100% of the dividend in U.S. acquisitions and drilling activities in 2006.

(5) INCOME TAXES: (Continued)

Deferred income taxes generally result from recognizing income and expenses at different times for financial and tax reporting. In the United States, the largest differences are the tax effect of the capitalization of certain development, exploration, and other costs under the full cost method of accounting, recording proceeds from the sale of properties in the full cost pool, and the provision for impairment of oil and gas properties for financial accounting purposes. In Canada, differences result in part from accelerated cost recovery of oil and gas capital expenditures for tax purposes.

The Company's deferred income tax expense excludes amounts related to the tax benefit of stock options exercised in 2005, 2004, and 2003 for which the related tax benefit was credited directly to shareholders' equity.

The components of the net deferred tax liability by geographical segment at December 31, 2005 and 2004 are as follows:

	December 31, 2005		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Allowance for doubtful accounts	$ 761	—	761
Investment in equity affiliate	2,166	—	2,166
Accrual for post retirement benefits	6,765	—	6,765
Unrealized losses on derivative contracts, net	60,211	—	60,211
Net operating loss carryforwards	184,577	2,497	187,074
Capital loss carryforward	115	3,937	4,052
Depletion carryforward	7,554	—	7,554
Alternative minimum tax credit carryforward	1,978	—	1,978
Other	8,691	417	9,108
Total gross deferred tax assets	272,818	6,851	279,669
Less valuation allowance	(45,340)	(3,937)	(49,277)
Net deferred tax assets	227,478	2,914	230,392
Deferred tax liabilities:			
Property and equipment	(405,130)	(74,134)	(479,264)
Other	(1,661)	(1,506)	(3,167)
Total gross deferred tax liabilities	(406,791)	(75,640)	(482,431)
Net deferred tax liabilities	$(179,313)	(72,726)	(252,039)

(5) INCOME TAXES: (Continued)

	December 31, 2004		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Allowance for doubtful accounts	$ 595	—	595
Investment in equity affiliate	2,061	—	2,061
Accrual for post retirement benefits	5,881	—	5,881
Unrealized losses on derivative contracts, net	37,226	—	37,226
Net operating loss carryforwards	171,842	1,922	173,764
Capital loss carryforward	115	4,833	4,948
Depletion carryforward	7,554	—	7,554
Alternative minimum tax credit carryforward	3,454	—	3,454
Other	6,110	—	6,110
Total gross deferred tax assets	234,838	6,755	241,593
Less valuation allowance	(85,960)	(5,851)	(91,811)
Net deferred tax assets	148,878	904	149,782
Deferred tax liabilities:			
Property and equipment	(257,582)	(46,208)	(303,790)
Other	(2,483)	(1,713)	(4,196)
Total gross deferred tax liabilities	(260,065)	(47,921)	(307,986)
Net deferred tax liabilities	$(111,187)	(47,017)	(158,204)

The net deferred tax liabilities are reflected in the accompanying balance sheets as follows:

	December 31, 2005		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax assets	$ 77,346	—	77,346
Non-current deferred tax liabilities	(256,659)	(72,726)	(329,385)
Net deferred tax liabilities	$(179,313)	(72,726)	(252,039)

	December 31, 2004		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax assets	$ 38,321	—	38,321
Non-current deferred tax liabilities	(149,508)	(47,017)	(196,525)
Net deferred tax liabilities	$(111,187)	(47,017)	(158,204)

SFAS 109 requires that the Company continually assess both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. In assessing whether deferred tax assets are realizable, management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies.

(5) INCOME TAXES: (Continued)

The net changes in the valuation allowance for the years ended December 31, 2005, 2004, and 2003 were as follows:

	2005	2004	2003
		(In Thousands)	
Net decrease in the valuation allowance for deferred tax assets attributable to reassessment of the amount of tax losses of acquired subsidiary expected to be utilized	$(36,608)	(4,044)	—
Decrease in the valuation allowance for net expiring operating loss carryforwards	(3,483)	(25,313)	(5,099)
Other decreases in the valuation allowance for deferred tax assets	(2,443)	—	—
Net decrease in the valuation allowance	$(42,534)	(29,357)	(5,099)

The $36.6 million decrease in valuation allowance for deferred tax assets in 2005 relates to tax loss carryforwards of an acquired subsidiary expected to be utilized in 2005 and future years which were previously provided for. A corresponding adjustment has been recorded to capital surplus. The other decreases in the valuation allowance of $2.4 million relate to adjustments to state and Canadian tax loss carryforwards.

The Alternative Minimum Tax (“AMT”) credit carryforward available to reduce future U.S. federal regular taxes aggregated $2.0 million at December 31, 2005. This amount may be carried forward indefinitely. U.S. federal regular and AMT net operating loss carryforwards at December 31, 2005 were approximately $506.3 million and $386.6 million, respectively. Of these amounts, approximately $221.6 million and $184.9 million were acquired by the Company in a merger that occurred in 2000 (the “Forcenergy Merger”); and approximately $39.8 million and $30.6 million were acquired by the

(5) INCOME TAXES: (Continued)

Company in its acquisitions of other corporate entities. The Company's regular and AMT net operating losses are scheduled to expire in the years indicated below:

	Regular	AMT
	(In Thousands)	
2005	$ 28,476	15,792
2006	18,638	14,996
2007	21,455	7,992
2008	64,024	8,394
2009	31,616	22,861
2010	48,432	39,338
2011	1,027	—
2012	206	2,158
2017	69,110	67,599
2018	39,143	40,587
2019	6,348	6,117
2020	1,947	1,946
2021	19,628	19,623
2022	136,635	139,152
2023	3,364	—
2024	16,251	—
	$506,300	386,555

AMT net operating loss carryforwards can be used to offset 90% of AMT income in future years.

The Company's ability to use some of its net operating loss carryforwards and certain other tax attributes to reduce current and future U.S. federal taxable income is subject to limitations under the Internal Revenue Code. In particular, the Company's ability to utilize such carryforwards is limited due to the occurrence of "Ownership Changes" within the meaning of Section 382 of the Internal Revenue Code. Ownership Changes occurred in the Company in 1995 following the issuance of securities to The Anschutz Corporation ("Anschutz"), in 1996 following a public stock issuance, and in connection with the 2000 Forcenergy Merger.

Ownership Changes occurred in Forcenergy in 1995 as a result of an initial public offering and merger with another entity, and in 2000 following its emergence from bankruptcy. These Ownership Changes will affect the use of tax attributes acquired in the Forcenergy Merger. Portions of Forcenergy's net operating loss carryforwards and other tax attributes are further limited due to Ownership Changes that occurred with respect to businesses acquired by Forcenergy in 1997. Ownership Changes also occurred in connection with Forest's acquisitions of other corporate entities. Forest does not expect these Ownership Changes to materially affect its ability to use those entities' tax attributes in the future.

Approximately $78 million of Forest's net operating loss carryforwards are subject to an annual limitation of approximately $5.8 million. In addition, Forest's ability to utilize substantially all of Forcenergy's built-in losses and net operating loss carryforwards will be subject to an overall annual

(5) INCOME TAXES: (Continued)

limitation of approximately $22 million. Additional limitations affect Forest's ability to utilize certain portions of Forcenergy's built-in losses and net operating loss carryforwards generated prior to 1997. Because of these limitations, approximately $70 million of these losses will not be realized before they expire. The Company believes it is more likely than not that additional carryforwards will expire before they can be realized and has provided a valuation allowance for its estimate of the total amounts that will not ultimately be realized due to limitations imposed by Section 382.

Canadian tax pools relating to the exploration, development, and production of oil and natural gas that are available to reduce future Canadian federal income taxes aggregated approximately $197.9 million ($229.9 million CDN) at December 31, 2005. The Canadian tax pools include approximately $57.8 million ($67.1 million CDN) acquired from predecessor companies that are limited in use to income derived from assets acquired. These tax pool balances are deductible on a declining balance basis ranging from 4% to 100% of the balance annually, and are composed of costs incurred for oil and gas properties, and developmental and exploration expenditures, as follows:

	2005	2004
	(In Thousands of Canadian Dollars)	
Canadian capital cost allowance	$ 56,818	43,311
Canadian development expense	86,881	78,471
Canadian exploration expense	44,273	97,301
Canadian oil and gas property expense	41,970	34,615
	$229,942	253,698

Other Canadian tax pools and loss carryforwards available to reduce future Canadian federal income taxes were approximately $26.7 million ($31.0 million CDN) at December 31, 2005, of which $19.3 million may be carried forward indefinitely.

(6) SHAREHOLDERS' EQUITY:

Common Stock

At December 31, 2005, the Company had 200 million shares of common stock ("Common Stock"), par value $.10 per share, authorized.

In June 2004, Forest issued 5.0 million shares of Common Stock at a price of $24.40 per share. Net proceeds from this offering were approximately $117.1 million after deducting underwriting discounts and commissions and estimated offering expenses. The net proceeds from the offering were used to fund a portion of the Wiser Acquisition.

In October 2003, Forest issued 5.1 million shares of Common Stock at a price of $23.10 per share. Net proceeds from this offering were approximately $112.6 million after deducting underwriting discounts and commissions and estimated offering expenses, and were used to fund a portion of the Unocal acquisition.

Forest issued 7.9 million shares of Common Stock at a price of $24.50 per share in January 2003. Net proceeds from this offering (before any exercise of the underwriters' over-allotment option) were approximately $184.4 million after deducting underwriting discounts and commissions and the estimated

(6) SHAREHOLDERS' EQUITY: (Continued)

expenses of the offering. An additional .9 million shares of Common Stock were issued in February 2003 pursuant to exercise of the underwriters' over-allotment option for net proceeds of $21.2 million.

Rights Agreement

In October 1993, the Board of Directors adopted a shareholders' rights plan and entered into the Rights Agreement. The Company distributed one Preferred Share Purchase Right (the "Rights") for each outstanding share of the Company's Common Stock. The Rights are exercisable only if a person or group acquires 20% or more of the Company's Common Stock or announces a tender offer that would result in ownership by a person or group of 20% or more of the Common Stock.

In October 2003, the Board of Directors of Forest entered into the First Amended and Restated Rights Agreement (the "First Amended Rights Agreement"). The rights issued under the First Amended Rights Agreement will expire on October 29, 2013, unless earlier exchanged or redeemed, and entitle the holder thereof to purchase 1/100th of a preferred share at an initial purchase price of $120.

Warrants

At December 31, 2005, Forest did not have any warrants outstanding. During 2005, two series of warrants expired, including warrants that expired on February 15, 2005 ("2005 Warrants") in accordance with the terms of the warrants. In April 2005, Forest provided notice of acceleration of subscription warrants ("Subscription Warrants") that were originally set to expire on March 20, 2010, and on May 9, 2005 all of the remaining unexercised Subscription Warrants expired.

The 2005 Warrants and Subscription Warrants were originally issued by Forcenergy Inc in connection with its plan of reorganization under the Bankruptcy Code and were converted into warrants to purchase Forest Common Stock pursuant to Forest's merger with Forcenergy in December 2000. The 2005 Warrants entitled the holder to purchase 0.8 shares of Common Stock for $20.83, or an equivalent per share price of $26.04. The Subscription Warrants entitled the holder to purchase 0.8 shares of Common Stock for $10.00, or an equivalent per share price of $12.50.

In connection with the expiration of the 2005 Warrants and the Subscription Warrants during 2005, a total of 1,907,333 warrants to purchase shares of Common Stock were exercised. As a result of these exercises, in 2005 Forest received cash proceeds of $14.4 million and issued a total of 1,358,350 shares of Common Stock.

During the years ending December 31, 2004 and 2003, warrants totaling 267,508 and 1,972, respectively, were exercised to purchase 162,901 and 1,573 shares of Common Stock, respectively.

Equity Incentive Plans

In 2001, the Company adopted the Forest Oil Corporation 2001 Stock Incentive Plan (the "2001 Plan") under which qualified and non-qualified stock options, restricted stock, and other awards may be granted to employees, consultants and non-employee directors. In 2003, the Company amended the 2001 Plan to increase the number of shares reserved for issuance. The aggregate number of shares of

(6) SHAREHOLDERS' EQUITY: (Continued)

Common Stock that the Company may issue under the 2001 Plan may not exceed 3.8 million shares. The exercise price of an option shall not be less than the fair market value of one share of Common Stock on the date of grant. Options under the 2001 Plan generally vest in increments of 25% on each of the first four anniversary dates of the date of grant and have a term of ten years. As of December 31, 2005, the Company had 330,147 shares available to be issued under the 2001 Plan. As a result of the Spin-off, outstanding stock options and the shares available for grant for all employees under the 2001 Plan will be adjusted to reflect the economic effect of the Spin-off.

The Company had a Stock Incentive Plan (the "1996 Plan") that expired on March 5, 2002 under which non-qualified stock options and restricted stock were granted to employees and director stock awards were granted to non-employee directors. Options granted under the 1996 Plan generally vested in increments of 20% commencing on the date of grant and on each of the first four anniversaries of the date of the grant.

Stock Options

The following table summarizes stock option activity in the Company's stock-based compensation plans for the years ended December 31, 2005, 2004, and 2003:

	Number of Shares	Weighted Average Exercise Price	Number of Shares Exercisable
Outstanding at January 1, 2003	3,615,544	$25.26	2,374,436
Granted at fair value	749,000	23.00	
Exercised	(486,508)	16.03	
Cancelled	(412,607)	29.91	
Outstanding at December 31, 2003	3,465,429	25.51	2,368,908
Granted at fair value	1,502,450	28.21	
Exercised	(827,817)	23.20	
Cancelled	(369,250)	28.24	
Outstanding at December 31, 2004	3,770,812	26.82	1,841,439
Granted at fair value	180,700	38.82	
Exercised	(1,078,067)	26.32	
Cancelled	(295,210)	27.71	
Outstanding at December 31, 2005	2,578,235	$27.78	1,348,599

(6) SHAREHOLDERS' EQUITY: (Continued)

The fair value of each option granted in 2005, 2004, and 2003 was estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair market value of options granted during the periods presented:

	2005	2004	2003
Expected life of options	5 years	5 years	5 years
Risk free interest rates	3.64% - 4.45%	2.98% - 4.01%	2.27% - 3.61%
Estimated volatility	28%	39%	48%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of options granted during the year	$12.77	$11.64	$10.48

The following table summarizes information about options outstanding at December 31, 2005:

Stock Options Outstanding				Stock Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$12.50 - 23.26	471,878	6.73	$21.98	261,728	$21.27
23.35 - 25.04	624,305	7.56	25.00	295,931	24.98
25.09 - 29.75	535,400	5.34	28.14	494,275	28.28
30.00 - 30.61	684,552	8.92	30.59	177,640	30.60
30.65 - 46.13	258,900	8.01	36.59	119,025	33.68
47.56 - 52.35	3,200	9.78	47.86	—	—
$12.50 - 52.35	2,578,235	7.36	$27.78	1,348,599	$26.98

As a result of the Spin-off, the Company will adjust all outstanding stock options to reflect the economic effect of the transaction. The adjustment formula will decrease the exercise price and increase the number of shares underlying the options outstanding.

Restricted Stock and Phantom Stock Units

During the years ended December 31, 2005 and 2004, the Company granted 548,000 and 95,600 shares of restricted common stock, respectively, valued at $25.1 million and $2.8 million, respectively. The restricted stock awards generally vest on the third anniversary of the date of the award. During the year ended December 31, 2005, the Company granted 72,350 phantom stock units valued at $3.3 million as compensation to Canadian employees. The units generally vest on the third anniversary of the date of the award and, at the Company's discretion, may be settled in either cash or in shares of Common Stock. The value of the restricted stock awards was recorded as deferred compensation in shareholders' equity. The Company recorded amortization of deferred stock based compensation of $1.2 million and $.2 million during the years ended December 31, 2005 and 2004, respectively, related to these equity awards.

(6) SHAREHOLDERS' EQUITY: (Continued)

Employee Stock Purchase Plan

The Company has in place a 1999 Employee Stock Purchase Plan (the "ESPP"), under which it is authorized to issue up to 300,000 shares of Common Stock. Employees who are regularly scheduled to work more than 20 hours per week and more than five months in any calendar year may participate in the ESPP. Under the terms of the ESPP, employees may elect each quarter to have up to 15% of their annual base earnings withheld to purchase Common Stock, up to a limit of $25,000 of Common Stock per calendar year. The purchase price of the Common Stock is equal to 85% of the lower of the beginning-of-quarter or end-of-quarter market price. ESPP participants are restricted from selling the shares of Common Stock purchased under the ESPP for a period of six months after purchase. Under the ESPP, the Company sold 18,589 shares, 22,207 shares, and 21,403 shares of Common Stock to employees in 2005, 2004, and 2003, respectively. As of December 31, 2005, the Company had 189,264 shares available for issuance under the ESPP.

The fair value of each stock purchase right granted under the ESPP during 2005, 2004, and 2003 was estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair market value of purchase rights granted during the periods presented:

	2005	2004	2003
Expected option life	3 months	3 months	3 months
Risk free interest rates	2.32% - 3.61%	0.93% - 1.71%	0.89% - 1.22%
Estimated volatility	26%	23%	26%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of purchase rights granted	$12.11	$7.91	$7.20

(7) EMPLOYEE BENEFITS:

United States Pension Plans and Postretirement Benefits

The Company has a qualified defined benefit pension plan that covers certain employees and former employees in the United States (the "Forest Pension Plan"). The Company also has a non-qualified unfunded supplementary retirement plan (the "Supplemental Executive Retirement Plan" or "SERP") that provides certain retired executives with defined retirement benefits in excess of qualified plan limits imposed by federal tax law. The Forest Pension Plan and the SERP were curtailed and all benefit accruals under both plans were suspended effective May 31, 1991.

In addition, as a result of the Wiser Acquisition, Forest assumed a noncontributory defined benefit pension plan (the "Wiser Pension Plan"). The Wiser Pension Plan was curtailed and all benefit accruals were suspended effective December 11, 1998. In October 2000, the Wiser Pension Plan was amended to provide additional benefits by implementing a cash balance plan for the then current employees of Wiser. In December 2004, all benefit accruals under the Wiser Pension Plan were suspended.

(7) EMPLOYEE BENEFITS: (Continued)

Amounts for the Forest Pension Plan, the SERP, and the Wiser Pension Plan are combined in the "Pension Benefits" column below. The weighted average asset allocations of the Forest Pension Plan and Wiser Pension Plan at December 31, 2005 and 2004 were:

	Forest Pension Plan		Wiser Pension Plan	
	2005	2004	2005	2004
Fixed income securities	49%	49%	18%	24%
Equity securities	50%	40%	44%	49%
Other	1%	11%	38%	27%
	100%	100%	100%	100%

The Forest Pension Plan, the Wiser Pension Plan, and the SERP are collectively referred to as the "Plans." Forest anticipates that it will make contributions in 2006 totaling $1.1 million to the Plans.

The overall investment goal for pension plan assets is to achieve an investment return that allows plan assets to achieve the assumed actuarial interest rate and to exceed the rate of inflation. In order to manage risk, in terms of volatility, the portfolios are designed to avoid a loss of 20% during any single year and to express no more volatility than experienced by the S&P 500 Stock Index.

The Plans' assets are invested with a view toward the long term in order to fulfill the obligations promised to participants as well as to control future levels of funding. The long-term goal for equity securities exposure is 50% of plan assets at market value. The maximum allowable equity exposure is 60%. There is no specified minimum equity exposure for any point in time. The long-term goal for fixed income exposure is 50% of the plan assets at market value. The maximum allowable fixed income exposure is 70%. There is no specified minimum fixed income exposure for any point in time. This asset allocation is designed to achieve an appropriate balance between capital appreciation, preservation of capital, and current income.

In addition to the Plans described above, Forest also accrues expected costs of providing postretirement benefits to employees in the United States, their beneficiaries, and covered dependents in accordance with Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* ("SFAS No. 106"). These amounts, which consist primarily of medical benefits payable on behalf of retirees in the United States, are presented in the "Postretirement Benefits" column below. Contributions to be made in 2006 for post retirement benefits other than pensions are expected to be approximately $.5 million, net of retiree contributions.

In the future, it is anticipated that the Company will be required to provide benefit payments from the Forest Pension Plan and the Wiser Pension Plan and fund benefit payments directly for the SERP

(7) EMPLOYEE BENEFITS: (Continued)

and the other postretirement benefits plans in 2006 through 2010 and in the aggregate for the years 2011 through 2015 in the following amounts:

	2006	2007	2008	2009	2010	2011-2015
			(In Thousands)			
Forest Pension Plan[(1)]	$2,377	2,349	2,361	2,340	2,309	11,059
SERP	61	59	57	55	53	222
Wiser Pension Plan[(1)]	819	809	795	799	802	4,000
Postretirement benefits	591	598	592	591	632	3,379

(1) Benefit payments expected to be made to participants in the Forest Pension Plan and Wiser Pension Plan are expected to be paid out of funds held in trusts established for each plan.

The discount rates used to determine benefit obligations was reduced from 5.75% at December 31, 2004 to between 5.32% and 5.46%, depending on the timing of the expected future distributions under the various plans. The discount rates were determined by adjusting the Moody's Aa Corporate bond yield to reflect the difference between the duration of the future estimated cash flows of the Plans and the other postretirement benefit obligations and the duration of the Moody's Aa index.

Forest developed its expected rate of return on plan assets by evaluating input from external consultants and long-term inflation assumptions. The expected long-term rate of return is based on the target allocation of plan assets.

The following tables set forth the estimated benefit obligations, the fair value of the Plans' assets, and the funded status of the Plans and the other postretirement benefit plans at December 31, 2005 and 2004:

Benefit Obligations

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
		(In Thousands)		
Projected benefit obligation at the beginning of the year	$40,921	29,846	10,536	9,490
Assumption of Wiser Pension Plan	—	11,022	—	—
Service cost	—	81	667	631
Interest cost	2,325	2,057	454	553
Actuarial (gain) loss	2,875	1,225	(1,439)[(1)]	288
Settlements	—	(518)	—	—
Benefits paid	(3,317)	(2,792)	(642)	(496)
Retiree contributions	—	—	78	70
Projected benefit obligation at the end of the year	$42,804	40,921	9,654	10,536

(1) The actuarial gain of $1.4 million in 2005 for the postretirement benefit includes approximately $.6 million associated with the federal subsidy provided by the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

(7) EMPLOYEE BENEFITS: (Continued)

Fair Value of Plan Assets

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
	(In Thousands)			
Fair value of plan assets at beginning of the year	$33,405	22,084	—	—
Assumption of Wiser Pension Plan	—	7,581	—	—
Actual return on plan assets	1,794	2,064	—	—
Retiree contributions	—	—	78	70
Employer contribution	2,590	4,986	564	426
Benefits paid	(3,317)	(3,310)	(642)	(496)
Fair value of plan assets at the end of the year	$34,472	33,405	—	—

Funded Status

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
	(In Thousands)			
Excess of projected benefit obligation over plan assets	$(8,332)	(7,516)	(9,654)	(10,536)
Unrecognized actuarial loss	13,920	11,247	241	1,680
Net amount recognized	$ 5,588	3,731	(9,413)	(8,856)
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability	$(8,332)	(7,516)	(9,413)	(8,856)
Accumulated other comprehensive income	13,920	11,247	—	—
Net amount recognized	$ 5,588	3,731	(9,413)	(8,856)

(7) EMPLOYEE BENEFITS: (Continued)

The following tables set forth the components of the net periodic cost and the underlying weighted average actuarial assumptions for the years ended December 31, 2005, 2004, and 2003:

	Pension Benefits			Postretirement Benefits		
	2005	2004	2003	2005	2004	2003
	(In Thousands)					
Service cost	$ —	81	—	667	631	530
Interest cost	2,325	2,056	1,814	454	553	523
Expected return on plan assets	(2,346)	(1,843)	(1,362)	—	—	—
Recognized actuarial loss	753	692	728	—	46	—
Settlement loss	—	20	—	—	—	—
Total net periodic expense	$ 732	1,006	1,180	1,121	1,230	1,053
Assumptions used to determine net periodic expense:						
Discount rate	5.75%	6.00%	6.50%	5.75%	6.00%	6.50%
Expected return on plan assets	*	*	7.00%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:						
Discount rate	5.32%	5.75%	6.00%	5.46%	5.75%	6.00%

* The expected return on plan assets of the Forest Pension Plan and the Wiser Pension Plan was 7.00% and 8.00%, respectively.

Assumed health care cost trend rates have a significant effect on the amounts reported for postretirement benefits. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2005:

	Postretirement Benefits	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	$ 321	(198)
Effect on postretirement benefit obligation	$1,753	(1,350)

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits was held constant at 5.5% during 2005 and thereafter.

Canadian Pension Plan and Postretirement Benefits

All employees of Canadian Forest participate in a defined contribution pension plan (the "Defined Contribution Pension Plan"). The expense associated with the contributions made by Canadian Forest to the Defined Contribution Pension Plan was $.3 million CDN in both 2005 and 2004, and $.4 million CDN in 2003.

(7) EMPLOYEE BENEFITS: (Continued)

Prior to 2003, contributions to the Defined Contribution Benefit Plan were taken from the surplus in a non-contributory defined benefit pension plan (the "Defined Benefit Pension Plan") sponsored by Canadian Forest. Under a plan to wind up the Defined Benefit Pension Plan, participating employees were provided an option to transfer an actuarially computed value to their defined contribution pension plan or to have an annuity purchased on their behalf from an insurance company. At December 31, 2003, all annuities had been purchased or computed values transferred out, resulting in the recognition of a net loss of $.8 million CDN in 2003 and Canadian Forest had no further obligations under the Defined Benefit Pension Plan. Consents from the provincial and federal governments to formally wind up the plan were received in May 2004.

Canadian Forest also accrues expected costs of providing postretirement benefits to certain of its employees, their beneficiaries, and covered dependents in accordance with SFAS No. 106. These amounts, which consist primarily of medical and dental benefits payable on behalf of retirees in Canada, are presented in the "Postretirement Benefits" column below. The postretirement benefit plan is closed to new participants. In the future, it is anticipated that Canadian Forest will make contributions equal to the benefits to be paid out. The benefits expected to be paid in each year from 2006 through 2010 are $48,000 CDN, $51,000 CDN, $53,000 CDN, $55,000 CDN, and $57,000 CDN, respectively. The aggregate benefits expected to be paid in the five years from 2011 through 2015 are $325,000 CDN.

The following tables set forth the estimated benefit obligation, fair value of the assets, and funded status of the Canadian postretirement benefits plan at December 31, 2005 and 2004:

Benefit Obligation

	Postretirement Benefits	
	2005	2004
	(In Thousands of Canadian Dollars)	
Projected benefit obligation at the beginning of the year	$731	507
Service cost	5	17
Interest cost	45	33
Actuarial (gain) loss	—	208
Benefits paid	(34)	(34)
Projected benefit obligation at the end of the year	$747	731

(7) EMPLOYEE BENEFITS: (Continued)

Fair Value of Plan Assets

	Postretirement Benefits 2005	Postretirement Benefits 2004
	(In Thousands of Canadian Dollars)	
Fair value of plan assets at beginning of the year	$ —	—
Actual return on plan assets	—	—
Employer contributions	34	34
Benefits paid	(34)	(34)
Fair value of plan assets at the end of the year	$ —	—

Funded Status

	Postretirement Benefits 2005	Postretirement Benefits 2004
	(In Thousands of Canadian Dollars)	
Excess of projected benefit obligation over plan assets	$(747)	(731)
Unamortized transitional obligation asset	—	—
Unamortized net actuarial loss	—	—
Net amount recognized	$(747)	(731)

(7) EMPLOYEE BENEFITS: (Continued)

The following table sets forth the components of net periodic pension cost of the Defined Benefit Pension Plan and the Canadian postretirement benefits plan and the underlying weighted average actuarial assumptions for the years ended December 31, 2005, 2004, and 2003.

	Pension Benefits	Postretirement Benefits		
	2003	2005	2004	2003
	(In Thousands of Canadian Dollars)			
Service cost	$ 375	5	17	17
Interest cost	378	45	33	32
Expected return on plan assets	(361)	—	—	—
Amortization of transition asset	(227)	—	—	—
Recognized actuarial (gains) losses	182	—	208	(218)
Settlement gain	(157)	—	—	—
Curtailment loss	900	—	—	—
Total net periodic pension expense (benefit)	$1,090	50	258	(169)
Assumptions used to determine net periodic expense (benefit):				
Discount rate	6.50%	6.00%	6.75%	7.00%
Expected return on plan assets	7.00%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:				
Discount rate	n/a	4.72%	6.00%	6.75%

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits for Canadian Forest was assumed to be 4% per year for the dental plan; 5% per year for Provincial health care; and 6.25% in 2006, 5.50% in 2007, 4.75% in 2008, and 4% thereafter for the medical plan.

Employee Retirement Savings Plans

Forest sponsors a qualified tax-deferred savings plan ("Retirement Savings Plan") for its employees in the United States in accordance with the provisions of Section 401(k) of the Internal Revenue Code. Employees may defer up to 80% of their compensation, subject to certain limitations. In 2003, the Company matched employee contributions up to 6% of eligible employee compensation. Effective January 1, 2004, the Company matching percentage increased to 7% of eligible employee compensation. Expenses associated with the Company's contributions to the Retirement Savings Plan totaled $2.2 million in 2005, $1.9 million in 2004, and $1.4 million in 2003. In each of these years, the Company matched employee contributions in cash.

Canadian Forest provides a savings plan ("Canadian Savings Plan") that is available to all of its employees. Employees may contribute up to 4% of their salary, subject to certain limitations, with Canadian Forest matching the employee contribution in full. The expense associated with Canadian Forest's contributions to the plan was approximately $.2 million in each of 2005, 2004, and 2003.

(7) EMPLOYEE BENEFITS: (Continued)

Due to the achievement of various corporate performance objectives in 2004, the Company contributed approximately $2.0 million as an employer discretionary contribution to the Retirement Savings Plan as well as an additional $.2 million to the Canadian Savings Plan. These discretionary contributions were paid in March 2005.

Deferred Compensation Plans

Forest has an Executive Deferred Compensation Plan (the "Executive Plan") pursuant to which certain officers may participate and defer a portion of their compensation after contributing the maximum allowable amount to the Retirement Savings Plan. The Executive Plan is not funded, but the Company records a liability for matching contributions and accrues interest on each participant's account balance at the rate of 1% per month. Effective January 1, 2006 the interest rate was changed to .5% per month. The expense associated with the Company's matching contributions to the Executive Plan and interest was $.4 million in both 2005 and 2004, and $.2 million in 2003. The liability associated with the Executive Plan was approximately $1.9 million and $1.6 million at December 31, 2005 and 2004, respectively.

Forest has also adopted two salary deferred compensation plans and a change of control deferred compensation plan. Eligibility to participate in the salary deferred compensation plans is limited to officers and directors of the Company, and officers may participate in the change of control deferred compensation plan. Under the terms of the salary deferred compensation plans, a participant may defer a percentage of his or her base salary, and bonuses. These plans were frozen at the end of 2005 and additional amounts may not be deferred. The change of control plan, which has not been implemented, allows participants to make one-time deferrals of compensation that they would otherwise receive upon a change in control of the Company. As of December 31, 2005 and 2004, the fair value of amounts deferred under the salary deferred compensation plans was approximately $.7 million and $.8 million, respectively.

Split Dollar Life Insurance

The Company provides life insurance benefits for certain retirees and former executives under split dollar life insurance plans. Under the life insurance plans, the Company is assigned a portion of the benefits. No current employees are covered by these plans.

(8) DERIVATIVE INSTRUMENTS:

Forest recognizes the fair value of its 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 and ineffective portions of hedges designated as cash flow hedges, changes in fair value are recognized in earnings as other income or expense.

(8) DERIVATIVE INSTRUMENTS: (Continued)

Commodity Hedges

Forest periodically hedges a portion of its oil and gas production through swap, basis swap, and collar agreements. The purpose of the hedges is to provide a measure of stability to Forest's cash flows in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk and protect the economics of property acquisitions. Forest's commodity hedges are generally designated as cash flow hedges; however, from time to time certain commodity hedges do not qualify for cash flow hedge accounting either at the inception of the hedge or during the term of the hedge, even though the instruments are expected to serve as effective economic hedges of Forest's commodity price exposure. As a result of production deferrals experienced in the Gulf of Mexico related to hurricanes Katrina and Rita, Forest was required to discontinue cash flow hedge accounting on certain natural gas and oil cash flow hedges during the third and fourth quarters of 2005. Additionally, certain hedges with terms covering periods throughout 2005 assumed in connection with business acquisitions could not be designated as cash flow hedges; however, all such hedges have expired as of December 31, 2005.

The tables below set forth, as of December 31, 2005, the quantity of oil and gas hedged under commodity swaps and collars. The tables identify which hedges qualify for hedge accounting and those that no longer qualify for hedge accounting as a result of the hurricanes as discussed above.

	Swaps			
	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Barrels Per Day	Weighted Average Hedged Price per Bbl
Cash flow hedge accounting				
First Quarter of 2006	50.0	$6.02	4,000	$31.58
Second Quarter 2006	50.0	6.02	4,000	31.58
Third Quarter 2006	50.0	6.02	4,000	31.58
Fourth Quarter 2006	50.0	6.02	4,000	31.58

(8) DERIVATIVE INSTRUMENTS: (Continued)

In connection with the Spin-off and Merger with Mariner completed on March 2, 2006 (see Note 2), three natural gas swaps included in the above table covering 40 Bbtus per day at an average fixed price of $6.15 were assigned to and assumed by Mariner.

	Costless Collars			
	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	Bbtu Per Day	Weighted Average Hedged Floor and Ceiling Price per MMBtu	Barrels Per Day	Weighted Average Hedged Floor and Ceiling Price per Bbl
Cash flow hedge accounting:				
First Quarter 2006	10.0	$6.13/10.75	1,000	$ 42.00/47.30
Second Quarter 2006	10.0	6.13/10.75	1,000	42.00/47.30
Third Quarter 2006	10.0	6.13/10.75	1,000	42.00/47.30
Fourth Quarter 2006	10.0	6.13/10.75	1,000	42.00/47.30
Non cash flow hedge accounting:				
First Quarter of 2006	40.0	7.75/12.16	4,500	47.78/70.00
Second Quarter 2006	40.0	7.75/12.16	4,500	47.78/70.00
Third Quarter 2006	40.0	7.75/12.16	4,500	47.78/70.00
Fourth Quarter 2006	40.0	7.75/12.16	4,500	47.78/70.00
Total:				
First Quarter of 2006	50.0	7.43/11.88	5,500	46.73/65.87
Second Quarter 2006	50.0	7.43/11.88	5,500	46.73/65.87
Third Quarter 2006	50.0	7.43/11.88	5,500	46.73/65.87
Fourth Quarter 2006	50.0	7.43/11.88	5,500	46.73/65.87

As of December 31, 2005, the Company had recorded net unrealized losses of $150.7 million related to its derivative instruments, which represented the fair values of the Company's open derivative contracts as of that date. These net unrealized losses are presented on the Consolidated Balance Sheet as a current liability of $152 million and a current asset of $1 million. Based on the estimated fair values of the derivative contracts that qualify for cash flow hedge accounting at December 31, 2005, the Company expects to reclassify net losses of $143.6 million ($89 million net of tax) out of accumulated other comprehensive income into earnings during the next 12 months; however, actual gains or losses recognized may differ materially.

The table below summarizes the realized and unrealized losses Forest incurred related to its hedging activities for the periods indicated. Realized gains and losses on hedges that qualify for the hedge accounting and are designated as cash flow hedges are recorded as an adjustment to oil and gas revenues while realized gains and losses on hedges that do not qualify for hedge accounting are recorded in other income or expense. The Company also measures and records ineffectiveness on hedges that qualify for cash flow hedge accounting but do not qualify as "perfect" hedges.

(8) DERIVATIVE INSTRUMENTS: (Continued)

Ineffectiveness occurs when the change in the fair value of the hedged item (i.e., future oil and natural gas production) is not equally offset by the change in the fair value of the hedging instrument.

	Years Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Realized losses on derivatives designated as cash flow hedges[1]	$(186,442)	(117,129)	(72,863)
Realized (losses) gains on derivatives not designated as cash flow hedges[2]	(35,390)	336	(68)
Ineffectiveness recognized on derivatives designated as cash flow hedges[2]	(5,747)	156	394
Unrealized (losses) gains on derivatives not designated as cash flow hedges[2]	(15,626)	(1,244)	57
Total realized and unrealized losses recorded	$(243,205)	(117,881)	(72,480)

(1) Included in oil and gas sales in the Consolidated Statements of Operations.

(2) Included in other expense (income), net in the Consolidated Statements of Operations.

In addition to the realized losses reflected in the tables above, Forest settled approximately $15.2 million in hedge losses in the fourth quarter of 2005, which were deferred until the first quarter of 2006 to correspond with the timing of the production that was deferred from hurricanes Katrina and Rita.

Interest Rate Swaps

Throughout 2001, 2002, and 2003, the Company entered into various interest rate swaps designated as fair value hedges intended to exchange (i) the fixed interest rate specified portions of its long term debt for (ii) a variable rate based on LIBOR plus specified basis points over the term of the debt instruments. During 2002 and 2003, the interest rate swaps were terminated for net proceeds of $35.6 million and $5.1 million, respectively. These gains were deferred and added to the carrying value of the related debt, and are being amortized as reductions of interest expense over the remaining terms of the notes. During the years ended December 31, 2005, 2004, and 2003, the Company recognized a portion of the gains by reducing interest expense by $4.9 million, $5.0 million, and $5.5 million, respectively.

(9) RELATED PARTY TRANSACTIONS:

Beginning in 1995, the Company consummated certain transactions with The Anschutz Corporation ("Anschutz") pursuant to which Anschutz acquired a significant ownership position in the Company. In January 2003, the Company issued 7.9 million shares of stock to the public at a gross price of $24.50 per share and used the net proceeds from the offering to repurchase 7.9 million shares of common stock from Anschutz and certain of its affiliates at a price of $23.52 per share. As of December 31, 2005, Anschutz owned approximately 12.6% of Forest's outstanding Common Shares. Based on reports filed with the SEC, as of March 3, 2006, Anschutz has entered into forward sales

(9) RELATED PARTY TRANSACTIONS: (Continued)

contracts covering 5.3 million shares of Common Stock that will settle in 2009 and 2010, and Anschutz retains voting rights for these shares through the settlement dates.

In 1998, Forest purchased certain oil and gas assets from Anschutz, including two concessions in South Africa. Over the years, the parties have entered into agreements concerning the development of these concession blocks. In March 2003, Forest entered into a Participation Agreement regarding the development of offshore South Africa acreage, including the Ibhubesi Gas Field, with The Petroleum Oil and Gas Corporation of South Africa (Pty) Limited (PetroSA) and Anschutz Overseas South Africa (Pty) Limited (Anschutz Overseas). As of February 28, 2006, the parties' interests in the concessions were as follows: Forest 53.2%, Anschutz Overseas 22.8%, and PetroSA 24.0%. Forest is the operator of these concession blocks and is reimbursed by the partners for exploration expenditures and general, technical and administrative overhead.

(10) COMMITMENTS AND CONTINGENCIES:

Future rental payments for office facilities, office equipment, and well equipment under the remaining terms of non-cancelable operating leases are $4.8 million, $3.8 million, $3.3 million, $3.0 million, and $3.1 million for the years ending December 31, 2006 through 2010, respectively. During the year ended December 31, 2005, the Company received approximately $5.0 million in corporate office lease concessions and incentives. These incentives were deferred and will be amortized as reductions in office lease expense over the term of lease through 2016. Amortization of lease concessions and incentives was $.1 million in 2005.

Net rental payments applicable to exploration and development activities and capitalized in the oil and gas property accounts aggregated $7.0 million in 2005, $5.6 million in 2004, and $5.9 million in 2003. Net rental payments charged to expense amounted to $11.2 million in 2005, $10.3 million in 2004, and $8.3 million in 2003. Rental payments include the short-term lease of vehicles. There are no leases that are accounted for as capital leases.

Forest, in the ordinary course of business, is a party to various lawsuits, claims, and proceedings. While we believe that the amount of any potential loss upon resolution of these matters 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 Forest's results of operations and cash flow in the reporting periods in which any such actions are resolved. Forest is also involved in a number of governmental proceedings in the ordinary course of business, including environmental matters.

Long-Term Sales Contracts

A portion of Canadian Forest's natural gas production is sold in a joint venture with other producers (the "Canadian Netback Pool"). The Canadian Netback Pool's resale markets are comprised of market based and fixed price contracts. Canadian Forest's contractual obligation to deliver natural gas production volumes to these contracts extends through 2011. Canadian Forest's average daily production sold through the Canadian Netback Pool represented approximately 5.5% of Forest's total average daily production in 2005. Canadian Forest supplied 46% of the Canadian Netback Pool sales quantity in 2005, and it is estimated that Canadian Forest will supply 54% of the Canadian Netback

(10) COMMITMENTS AND CONTINGENCIES: (Continued)

Pool quantity in the 2006 contract year. We expect that Canadian Forest's pro rata obligations as a gas producer will increase in 2006 and future years. At December 31, 2005, the weighted average price paid under the resale contracts was approximately 76% of market value based on the closing AECO prices on that date. To the extent the Canadian Netback Pool's supply is insufficient to meet the delivery obligations under the resale contracts, as is currently the case, the Canadian Netback Pool must make up the shortfall by purchasing spot market gas at prices that currently exceed the prices paid under the resale contracts.

(11) OTHER EXPENSE (INCOME)

The components of other expense (income), net for the years ended December 31, 2005, 2004, and 2003 were as follows:

	Year Ended December 31,		
	2005	2004	2003
	(In Thousands)		
Loss on extinguishment of debt	$ —	—	3,975
Foreign currency exchange gain	—	(4,728)	—
Franchise taxes	1,963	1,219	1,679
Forest's share of loss (income) of equity method investee	562	(1,726)	2,043
Other, net	3,722	3,056	(350)
Total other expense (income), net	$6,247	(2,179)	7,347

(12) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter[1]	Fourth Quarter
	(In Thousands Except Per Share Amounts)			
2005				
Revenue	$260,291	271,055	268,236	272,463
Earnings from operations	$ 83,129	97,480	91,919	96,811
Net earnings from continuing operations	$ 38,871	52,201	3,265	57,231
Net earnings	$ 38,871	52,201	3,265	57,231
Basic earnings per share from continuing operations	$ .65	.85	.05	.92
Basic earnings per share	.65	.85	.05	.92
Diluted earnings per share from continuing operations	.63	.83	.05	.90
Diluted earnings per share	.63	.83	.05	.90
2004				
Revenue	$194,253	208,478	245,393	264,774
Earnings from operations	$ 44,661	56,301	73,320	84,005
Net earnings from continuing operations	$ 19,637	28,130	31,775	43,584
Net earnings	$ 19,062	28,130	31,775	43,584
Basic earnings per share from continuing operations	$ .37	.51	.54	.73
Basic earnings per share	.36	.51	.54	.73
Diluted earnings per share from continuing operations	.36	.50	.53	.72
Diluted earnings per share	.35	.50	.53	.72

(1) Net earnings from continuing operations in the third quarter of 2005 were impacted by a charge of approximately $42.8 million for unrealized losses on derivative instruments that no longer qualified for hedge accounting as a result of hurricanes Katrina and Rita.

(13) BUSINESS AND GEOGRAPHICAL SEGMENTS:

Segment information has been prepared in accordance with Statement of Financial Accounting Standards No. 131, *Disclosures About Segments of an Enterprise and Related Information*. At December 31, 2005, Forest had five reportable segments consisting of oil and gas operations in five business units (Gulf Coast [renamed Southern after the Spin-off on March 2, 2006], Western, Alaska, Canada, and International). On March 1, 2004, the assets and business operations of the Company's gas marketing subsidiary, ProMark, were sold to Cinergy, as discussed in Note 2. Accordingly, ProMark's results of operations have been reported as discontinued operations. The Company's remaining marketing and processing activities are not significant and therefore are not reported as a separate segment, and are included as a reconciling item in the information below.

The segments were determined based upon the type of operations in each business unit and the geographical location of each. The segment data presented below was prepared on the same basis as the consolidated financial statements.

Year ended December 31, 2005

	Oil and Gas Operations						
	Gulf Coast	Western	Alaska	Total United States	Canada	International	Total Company
				(In Thousands)			
Revenue	$ 486,800	280,934	117,882	885,616	176,901	—	1,062,517
Expenses:							
Lease operating expenses	94,413	38,496	47,958	180,867	18,894	—	199,761
Production and property taxes	13,858	24,386	1,575	39,819	2,796	—	42,615
Transportation costs	3,822	2,429	7,554	13,805	5,694	—	19,499
General and administrative	10,424	6,234	2,828	19,486	5,183	671	25,340
Depletion	190,237	68,699	42,600	301,536	63,335	—	364,871
Impairment and other	8,208	—	—	8,208	—	2,924	11,132
Accretion of asset retirement obligations	13,806	961	1,556	16,323	962	32	17,317
Earnings (loss) from operations	$ 152,032	139,729	13,811	305,572	80,037	(3,627)	381,982
Capital expenditures[(1)]	$ 206,081	492,123	20,437	718,641	115,019	3,688	837,348
Net oil and gas properties	$1,281,249	1,019,304	364,118	2,664,671	453,150	56,637	3,174,458
Goodwill	$ 15,009	56,368	—	71,377	15,695	—	87,072

(1) Does not include estimated discounted asset retirement obligations of $16.3 million related to assets placed in service during the year ended December 31, 2005.

(13) BUSINESS AND GEOGRAPHICAL SEGMENTS: (Continued)

Information for reportable segments relates to the Company's 2005 consolidated totals as follows:

	(In Thousands)
Earnings from operations for reportable segments	$381,982
Marketing, processing, and other	9,528
Corporate general and administrative expense	(18,363)
Interest expense	(61,403)
Administrative asset depreciation	(3,808)
Realized losses on derivative instruments, net	(35,390)
Unrealized losses on derivative instruments, net	(21,373)
Other expense, net	(6,247)
Earnings before income taxes, discontinued operations, and cumulative effect of change in accounting principle	$244,926

Year ended December 31, 2004

	Oil and Gas Operations						
	Gulf Coast	Western	Alaska	Total United States	Canada	International	Total Company
	(In Thousands)						
Revenue	$ 566,177	172,500	60,913	799,590	110,190	—	909,780
Expenses:							
Lease operating expenses	106,514	29,860	34,925	171,299	17,862	—	189,161
Production and property taxes	12,296	15,821	2,981	31,098	1,143	—	32,241
Transportation costs	3,592	1,289	8,754	13,635	3,157	—	16,792
General and administrative	8,667	2,607	3,680	14,954	3,837	—	18,791
Depletion	212,784	33,390	58,400	304,574	45,737	—	350,311
Impairment and other	5,273	1,270	497	7,040	1,764	4,125	12,929
Accretion of asset retirement obligations	13,835	1,189	1,461	16,485	766	—	17,251
Earnings (loss) from operations	$ 203,216	87,074	(49,785)	240,505	35,924	(4,125)	272,304
Capital expenditures[1]	$ 255,892	258,352	21,928	536,172	158,310	5,755	700,237
Net oil and gas properties	$1,259,473	629,595	377,804	2,266,872	386,926	55,966	2,709,764
Goodwill	$ 16,859	37,525	—	54,384	14,176	—	68,560

(1) Does not include estimated discounted asset retirement obligations of $14.1 million related to assets placed in service during the year ended December 31, 2004.

(13) BUSINESS AND GEOGRAPHICAL SEGMENTS: (Continued)

Information for reportable segments relates to the Company's 2004 consolidated totals as follows:

	(In Thousands)
Earnings from operations for reportable segments	$272,304
Marketing, processing, and other	3,118
Corporate general and administrative expense	(13,354)
Interest expense	(57,844)
Administrative asset depreciation	(3,781)
Realized gains on derivative instruments, net	336
Unrealized losses on derivative instruments, net	(1,088)
Other income, net	2,179
Earnings before income taxes, discontinued operations, and cumulative effect of change in accounting principle	$201,870

Year ended December 31, 2003

	Oil and Gas Operations						
	Gulf Coast	Western	Alaska	Total United States	Canada	International	Total Company
	(In Thousands)						
Revenue	$ 416,454	98,388	75,375	590,217	64,976	—	655,193
Expenses:							
Lease operating expenses	64,749	13,776	32,196	110,721	13,761	—	124,482
Production and property taxes	7,107	8,258	4,056	19,421	508	—	19,929
Transportation costs	3,155	1,154	5,230	9,539	220	—	9,759
General and administrative	9,090	2,528	4,790	16,408	3,955	495	20,858
Depletion	148,745	18,547	34,851	202,143	28,917	—	231,060
Impairment and other	—	—	—	—	—	16,910	16,910
Accretion of asset retirement obligations	10,130	910	2,302	13,342	423	20	13,785
Earnings (loss) from operations	$ 173,478	53,215	(8,050)	218,643	17,192	(17,425)	218,410
Capital expenditures[1]	$ 412,072	193,014	68,933	674,019	46,518	8,211	728,748
Net oil and gas properties	$1,231,680	414,510	418,968	2,065,158	304,138	56,747	2,426,043

[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.

(13) BUSINESS AND GEOGRAPHICAL SEGMENTS: (Continued)

Information for reportable segments relates to the Company's 2003 consolidated totals as follows:

	(In Thousands)
Earnings from operations for reportable segments	$218,410
Marketing, processing, and other	1,985
Corporate general and administrative expense	(15,464)
Interest expense	(49,341)
Administrative asset depreciation	(3,762)
Realized losses on derivative instruments, net	(68)
Unrealized gains on derivative instruments, net	451
Other expense, net	(7,347)
Earnings before income taxes, discontinued operations, and cumulative effect of change in accounting principle	$144,864

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited):

The following information is presented in accordance with Statement of Financial Accounting Standards No. 69, *Disclosure about Oil and Gas Producing Activities* ("SFAS No. 69").

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

(A) Costs Incurred in Oil and Gas Exploration and Development Activities. The following costs were incurred in oil and gas acquisition, exploration, and development activities during the years ended December 31, 2005, 2004, and 2003:

	United States	Canada	International	Total
	(In Thousands)			
2005				
Property acquisition costs (undeveloped leases and proved properties)	$305,917	7,598	—	313,515
Exploration costs	179,006	77,448	3,688	260,142
Development costs	248,029	31,996	—	280,025
Total costs incurred[(1)]	$732,952	117,042	3,688	853,682
2004				
Property acquisition costs (undeveloped leases and proved properties)	$321,670	114,312	—	435,982
Exploration costs	69,325	19,542	5,755	94,622
Development costs	157,242	26,456	—	183,698
Total costs incurred[(1)]	$548,237	160,310	5,755	714,302
2003				
Property acquisition costs (undeveloped leases and proved properties)	$479,290	—	22	479,312
Exploration costs	66,310	32,350	8,189	106,849
Development costs	191,712	14,611	—	206,323
Total costs incurred[(1)]	$737,312	46,961	8,211	792,484

(1) Includes amounts relating to estimated asset retirement obligations of $16.3 million, $14.1 million, and $63.7 million for assets placed in service in the years ended December 31, 2005, 2004, and 2003, respectively.

(B) Aggregate Capitalized Costs. The aggregate capitalized costs relating to oil and gas activities at the end of each of the years indicated were as follows:

	2005	2004	2003
	(In Thousands)		
Costs related to proved properties	$5,957,805	5,201,562	4,590,469
Costs related to unproved properties	275,684	209,604	158,008
	6,233,489	5,411,166	4,748,477
Less accumulated depletion	(3,059,031)	(2,701,402)	(2,322,434)
	$3,174,458	2,709,764	2,426,043

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

(C) Results of Operations from Producing Activities. Results of operations from producing activities for the years ended December 31, 2005, 2004, and 2003 are presented below.

	United States	Canada	Total
		(In Thousands)	
2005			
Oil and gas sales	$885,616	176,901	1,062,517
Expenses:			
Production expense	234,491	27,384	261,875
Depletion expense	301,536	63,335	364,871
Impairment and other	8,208	—	8,208
Accretion of asset retirement obligations	16,323	962	17,285
Income tax expense	123,522	28,463	151,985
Total expenses	684,080	120,144	804,224
Results of operations from producing activities	$201,536	56,757	258,293
2004			
Oil and gas sales	$799,590	110,190	909,780
Expenses:			
Production expense	216,032	22,162	238,194
Depletion expense	304,574	45,737	350,311
Impairment and other	2,233	—	2,233
Accretion of asset retirement obligations	16,485	766	17,251
Income tax expense	98,901	13,952	112,853
Total expenses	638,225	82,617	720,842
Results of operations from producing activities	$161,365	27,573	188,938
2003			
Oil and gas sales	$590,217	64,976	655,193
Expenses:			
Production expense	139,681	14,489	154,170
Depletion expense	202,143	28,917	231,060
Accretion of retirement obligations	13,362	423	13,785
Income tax expense	89,312	9,404	98,716
Total expenses	444,498	53,233	497,731
Results of operations from producing activities	$145,719	11,743	157,462

(D) Estimated Proved Oil and Gas Reserves. The Company's estimate of its net proved and proved developed oil and gas reserves and changes for 2005, 2004, and 2003 follows. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made.

Prices include consideration of changes in existing prices provided only by contractual arrangement, but not on escalations based on future conditions. Prices do not include the effects of commodity hedges. Purchases of reserves in place represent volumes recorded on the closing dates of the acquisitions for financial accounting purposes.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

	Liquids (MBbls)			Gas (MMcf)			
	United States	Canada	Total	United States	Canada	Total	Total MMcfe
Balance at January 1, 2003	117,452	6,914	124,366	678,410	134,984	813,394	1,559,590
Revisions of previous estimates	(60,652)	885	(59,767)	(94,895)	(19,136)	(114,031)	(472,633)
Extensions and discoveries	674	468	1,142	36,314	14,647	50,961	57,813
Production	(7,686)	(1,015)	(8,701)	(84,368)	(12,609)	(96,977)	(149,183)
Sales of reserves in place	(2,303)	—	(2,303)	(7,364)	—	(7,364)	(21,182)
Purchases of reserves in place	26,587	—	26,587	162,085	—	162,085	321,607
Balance at December 31, 2003	74,072	7,252	81,324	690,182	117,886	808,068	1,296,012
Revisions of previous estimates	3,664	(359)	3,305	(20,125)	(6,586)	(26,711)	(6,881)
Extensions and discoveries	1,098	213	1,311	33,212	11,582	44,794	52,660
Production	(9,550)	(1,287)	(10,837)	(91,420)	(15,946)	(107,366)	(172,388)
Sales of reserves in place	(4,203)	(4,003)	(8,206)	(13,160)	(22,193)	(35,353)	(84,589)
Purchases of reserves in place	17,982	3,934	21,916	84,889	32,804	117,693	249,189
Balance at December 31, 2004	83,063	5,750	88,813	683,578	117,547	801,125	1,334,003
Revisions of previous estimates	10,225	(551)	9,674	11,720	1,299	13,019	71,063
Extensions and discoveries	3,388	1,002	4,390	50,276	38,651	88,927	115,267
Production	(9,316)	(1,252)	(10,568)	(82,912)	(18,921)	(101,833)	(165,241)
Sales of reserves in place	(1,272)	—	(1,272)	(7,390)	—	(7,390)	(15,022)
Purchases of reserves in place	5,990	43	6,033	87,902	2,933	90,835	127,033
Balance at December 31, 2005	92,078	4,992	97,070	743,174	141,509	884,683	1,467,103
Proved developed reserves at:							
December 31, 2003	53,942	6,917	60,859	518,317	91,781	610,098	975,252
December 31, 2004	61,494	5,551	67,045	532,810	94,320	627,130	1,029,400
December 31, 2005	66,818	4,779	71,597	524,424	114,932	639,356	1,068,938

During 2003, Forest revised downward its estimate of proved reserves by a total of approximately 473 Bcfe. The downward revision of the Company's estimates was due to information received from production results, drilling activity, and other events that occurred primarily in the latter part of 2003. Approximately 62% of the total revisions was attributable to the downward revision of the Company's estimate of proved oil reserves in the Redoubt Shoal Field in the Cook Inlet, Alaska. Forest reduced its estimate of proved oil reserves associated with its Redoubt Shoal Field from its 2002 year-end estimate by approximately 49 million barrels (294 Bcfe), or approximately 85% of the estimated proved oil reserves in the field as of December 31, 2002. Of this revision, approximately 36 million barrels were classified as proved undeveloped as of December 31, 2002.

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

(E) Standardized Measure of Discounted Future Net Cash Flows. Future oil and gas sales and production and development costs have been estimated using prices and costs in effect at the end of the years indicated, except in those instances where the sale of oil and natural gas is covered by contracts. Where the sale is covered by contracts, the applicable contract prices, including fixed and determinable escalations, were used for the duration of the contract. Thereafter, the current spot price was used. All cash flow amounts, including income taxes, are discounted at 10%.

Future income tax expenses are estimated using an estimated combined federal and state income tax rate of 38% in the United States and an average combined federal and provincial rate of 34% in Canada. Estimates for future general and administrative and interest expense have not been considered.

Changes in the demand for oil and natural gas, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. This table should not be construed to be an estimate of the current market value of the Company's proved reserves. Management does not rely upon the information that follows in making investment decisions.

	December 31, 2005		
	United States	Canada	Total
	(In Thousands)		
Future oil and gas sales	$11,247,050	1,322,259	12,569,309
Future production costs	(2,359,620)	(232,520)	(2,592,140)
Future development costs	(803,078)	(56,662)	(859,740)
Future income taxes	(2,514,541)	(256,888)	(2,771,429)
Future net cash flows	5,569,811	776,189	6,346,000
10% annual discount for estimated timing of cash flows	(2,230,609)	(262,766)	(2,493,375)
Standardized measure of discounted future net cash flows	$ 3,339,202	513,423	3,852,625

	December 31, 2004		
	United States	Canada	Total
	(In Thousands)		
Future oil and gas sales	$ 7,284,594	755,171	8,039,765
Future production costs	(1,817,089)	(165,915)	(1,983,004)
Future development costs	(663,272)	(38,956)	(702,228)
Future income taxes	(1,330,800)	(107,868)	(1,438,668)
Future net cash flows	3,473,433	442,432	3,915,865
10% annual discount for estimated timing of cash flows	(1,247,157)	(153,151)	(1,400,308)
Standardized measure of discounted future net cash flows	$ 2,226,276	289,281	2,515,557

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

	December 31, 2003		
	United States	Canada	Total
		(In Thousands)	
Future oil and gas sales	$ 6,215,949	734,742	6,950,691
Future production costs	(1,534,859)	(180,760)	(1,715,619)
Future development costs	(682,060)	(34,524)	(716,584)
Future income taxes	(962,745)	(110,379)	(1,073,124)
Future net cash flows	3,036,285	409,079	3,445,364
10% annual discount for estimated timing of cash flows	(974,915)	(162,519)	(1,137,434)
Standardized measure of discounted future net cash flows	$ 2,061,370	246,560	2,307,930

(F) Changes in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. An analysis of the changes in the standardized measure of discounted future net cash flows during each of the last three years is as follows:

	December 31, 2005		
	United States	Canada	Total
		(In Thousands)	
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$2,226,276	289,281	2,515,557
Changes resulting from:			
Sales of oil and gas, net of production costs	(840,297)	(149,517)	(989,814)
Net changes in prices and future production costs	1,414,816	206,500	1,621,316
Net changes in future development costs	(135,308)	(14,601)	(149,909)
Extensions, discoveries, and improved recovery	284,981	214,016	498,997
Previously estimated development costs incurred during the period	235,521	30,683	266,204
Revisions of previous quantity estimates	209,948	(7,930)	202,018
Sales of reserves in place	(44,100)	—	(44,100)
Purchases of reserves in place	298,189	9,186	307,375
Accretion of discount on reserves at beginning of year before income taxes	296,413	34,730	331,143
Net change in income taxes	(607,237)	(98,925)	(706,162)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$3,339,202	513,423	3,852,625

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2005 was based on average natural gas prices of approximately $8.44 per Mcf in the U.S. and approximately $7.78 per Mcf in Canada, and on average

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

liquids prices of approximately $54.03 per barrel in the U.S. and approximately $44.34 per barrel in Canada.

	December 31, 2004		
	United States	Canada	Total
	(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$2,061,370	246,560	2,307,930
Changes resulting from:			
Sales of oil and gas, net of production costs	(702,832)	(89,001)	(791,833)
Net changes in prices and future production costs	217,917	60,660	278,577
Net changes in future development costs	(49,696)	(16,053)	(65,749)
Extensions, discoveries, and improved recovery	153,376	32,159	185,535
Previously estimated development costs incurred during the period	152,641	30,577	183,218
Revisions of previous quantity estimates	11,024	(21,059)	(10,035)
Sales of reserves in place	(90,124)	(106,320)	(196,444)
Purchases of reserves in place	387,396	133,974	521,370
Accretion of discount on reserves at beginning of year before income taxes	262,221	29,305	291,526
Net change in income taxes	(177,017)	(11,521)	(188,538)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$2,226,276	289,281	2,515,557

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2004 was based on average natural gas prices of approximately $5.88 per Mcf in the U.S. and approximately $4.81 per Mcf in Canada, and on average

(14) SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)

liquids prices of approximately $39.23 per barrel in the U.S. and approximately $32.94 per barrel in Canada.

	December 31, 2003		
	United States	Canada	Total
	(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$1,843,797	209,351	2,053,148
Changes resulting from:			
Sales of oil and gas, net of production costs	(525,384)	(50,487)	(575,871)
Net changes in prices and future production costs	255,666	40,305	295,971
Net changes in future development costs	(71,827)	(6,897)	(78,724)
Extensions, discoveries, and improved recovery	141,622	31,936	173,558
Previously estimated development costs incurred during the period	185,823	14,416	200,239
Revisions of previous quantity estimates	(596,760)	(24,702)	(621,462)
Sales of reserves in place	(29,565)	—	(29,565)
Purchases of reserves in place	706,376	—	706,376
Accretion of discount on reserves at beginning of year before income taxes	232,387	26,226	258,613
Net change in income taxes	(80,765)	6,412	(74,353)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$2,061,370	246,560	2,307,930

In 2003, the Company recorded significant reductions in its estimates of proved reserves in the Redoubt Shoal Field in Alaska. These revisions were anomalous to the Company's reserve base in that the reserves from this field realize lower sales prices and higher operating costs than the United States properties as a whole. For this reason, the changes in standardized measure of discounted future net cash flows relating to the Company's U.S. proved oil and gas reserves for the year ended December 31, 2003 represent the sum of (i) the changes in standardized measure for the Company's Redoubt Shoal Field (calculated on a stand-alone basis) and (ii) the changes in standardized measure for the Company's other U.S. properties (calculated on an aggregate basis).

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2003 was 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.

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

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures.

We have established disclosure controls and procedures to ensure that material information relating to Forest and its consolidated subsidiaries is made known to the officers who certify Forest's financial reports and the Board of Directors.

Our Chief Executive Officer, H. Craig Clark, and our Chief Financial Officer, David H. Keyte, evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as of the end of the period covered by this Annual Report on Form 10-K (the "Evaluation Date"). Based on this evaluation, they believe that as of the Evaluation Date 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 Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms.

Changes in Internal Controls 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, 2005 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Managements' Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act, Rules 13a-15(f). Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control—Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2005. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Item 9B. Other Information.

None.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Forest Oil Corporation:

We have audited management's assessment, included in the accompanying Managements' Annual Report on Control Over Financial Reporting, that Forest Oil Corporation maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Forest Oil Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Forest Oil Corporation maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Forest Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Forest Oil Corporation and subsidiaries as of December 31, 2005 and 2004, 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, 2005, and our report dated March 13, 2006 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Denver, Colorado
March 13, 2006

PART III

Item 10. Directors and Executive Officers of the Registrant.

The names of the executive officers of Forest and their titles, ages, and biographies required by this Item are incorporated by reference to the information set forth under the caption "Executive Officers of Forest" included in Part I, Item 4A of this Form 10-K.

The following information will be included in Forest's Notice of Annual Meeting of Shareholders and Proxy Statement (the "Proxy Statement") to be filed with the SEC within 120 days after Forest's fiscal year end of December 31, 2005 and is incorporated herein by reference:

- Information concerning Forest's directors is incorporated by reference to the information under the caption "Proposal No. 1—Election of Directors"
- Information concerning Forest's Audit Committee and designated "audit committee financial expert" is set forth under the caption "Corporate Goveranance Principles and Information about the Board and its Committees"
- Information about Forest's code of ethics for directors, officers, and employees is set forth under the caption "Corporate Governance Principles and Information about the Board and its Committees"
- Information about compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance"

Item 11. Executive Compensation.

Information regarding Forest's compensation of its named executive officers is set forth under the captions "Executive Compensation" in the Proxy Statement, which information is incorporated herein by reference. Information regarding Forest's compensation of its directors is set forth under the caption "Corporate Governance Principles and Information about the Board and its Committees" in the Proxy Statement, which information is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Information regarding security ownership of certain beneficial owners, directors, and executive officers is set forth under the caption "Common Stock Ownership of Certain Beneficial Owners and Management" in the Proxy Statement, which information is incorporated herein by reference.

Information regarding Forest's equity compensation plans is set forth under the caption "Executive Compensation—Equity Compensation Plan Information" in the Proxy Statement, which information is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions.

Information regarding certain relationships and related transactions is set forth under the caption "Certain Relationships and Related Transactions" in the Proxy Statement, which information is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services.

Information regarding principal auditor fees and services is set forth under the captions "Principal Accountant Fees and Services" and "Report of the Audit Committee" in the Proxy Statement, which information is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) The following documents are filed as part of this report or are incorporated by reference:

(1) Financial Statements:

1. Independent Auditors' Report
2. Consolidated Balance Sheets—December 31, 2005 and 2004
3. Consolidated Statements of Operations—Years ended December 31, 2005, 2004, and 2003
4. Consolidated Statements of Shareholders' Equity—Years ended December 31, 2005, 2004, and 2003
5. Consolidated Statements of Cash Flows—Years ended December 31, 2005, 2004, and 2003
6. Notes to Consolidated Financial Statements—Years ended December 31, 2005, 2004, and 2003

(2) Financial Statement Schedules: All schedules have been omitted because the information is either not required or is set forth in the financial statements or the notes thereto.

(3) Exhibits: See the Index of Exhibits listed in Item 15(b) hereof for a list of those exhibits filed as part of this Form 10-K.

(b) Index of Exhibits:

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of Forest Oil Corporation dated October 14, 1993, incorporated herein by reference to Exhibit 3(i) to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 1993 (File No. 0-4597).
3.2	Certificate of Amendment of the Restated Certificate of Incorporation, dated as of July 20, 1995, incorporated herein by reference to Exhibit 3(i)(a) to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 1995 (File No. 0-4597).
3.3	Certificate of Amendment of the Certificate of Incorporation, dated as of July 26, 1995, incorporated herein by reference to Exhibit 3(i)(b) to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 1995 (File No. 0-4597).
3.4	Certificate of Amendment of the Certificate of Incorporation dated as of January 5, 1996, incorporated herein by reference to Exhibit 3(i)(c) to Forest Oil Corporation's Registration Statement on Form S-2 (File No. 33-64949).
3.5	Certificate of Amendment of the Certificate of Incorporation dated as of December 7, 2000, incorporated herein by reference to Exhibit 3(i)(d) to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).
3.6	Bylaws of Forest Oil Corporation Restated as of February 14, 2001 as amended by Amendments No. 1, No. 2 and No. 3, incorporated herein by reference to Exhibit 3.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2004 (File No. 001-13515).

Exhibit Number	Description
4.1	Indenture dated as of June 21, 2001 between Forest Oil Corporation and State Street Bank and Trust Company, incorporated herein by reference to Exhibit 4.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
4.2	Indenture dated December 7, 2001 between Forest Oil Corporation and State Street Bank and Trust Company, incorporated herein by reference to Exhibit 4.5 to Forest Oil Corporation's Registration Statement on Form S-4 dated February 6, 2002 (File No. 333-82254).
4.3	Indenture dated as of April 25, 2002 between Forest Oil Corporation and State Street Bank and Trust Company, incorporated herein by reference to Exhibit 4.6 to Forest Oil Corporation's Registration Statement on Form S-4 dated June 11, 2002 (File No. 333-90220).
4.4	Registration Rights Agreement dated as of May 19, 1995 between Forest Oil Corporation and The Anschutz Corporation incorporated by reference to Exhibit 4.21 to Form 10-K for Forest Oil Corporation for the year ended December 31, 1995 (file No. 001-13515).
4.5	Registration Rights Agreement, dated as of July 10, 2000, by and between Forest Oil Corporation and the other signatories thereto, incorporated herein by reference to Exhibit 4.15 to Forest Oil Corporation Registration Statement on Form S-4, dated November 6, 2000 (File No. 333-49376).
4.6	First Amended and Restated Rights Agreement, dated as of October 17, 2003, between Forest Oil Corporation and Mellon Investor Services LLC, incorporated herein by reference to Exhibit 4.1 to Forest Oil's Current Report on Form 8-K, dated October 17, 2003 (File No. 001-13515).
4.7	Mortgage, Deed of Trust, Assignment, Security Agreement, Financing Statement and Fixture Filing from Forest Oil Corporation to Robert C. Mertensotto, trustee, and Gregory P. Williams, trustee (Utah), and The Chase Manhattan Bank, as Global Administrative Agent, dated as of December 7, 2000, incorporated herein by reference to Exhibit 4.13 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).
4.8	U.S. Credit Agreement—Amended and Restated Credit Agreement dated as of September 28, 2004, among Forest Oil Corporation, each of the lenders that is party thereto, Bank of America, N.A. and Citibank, N.A., as Co-Global Syndication Agents, BNP Paribas and Harris Nesbitt Financing, Inc., as Co-U.S. Documentation Agents, and JPMorgan Chase Bank, as Global Administrative Agent, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2004 (File No. 001-13515).
4.9	Canadian Credit Agreement—Amended and Restated Credit Agreement dated as of September 28, 2004, among Forest Oil Corporation, each of the lenders that is party thereto, Bank of America, N.A. and Citibank, N.A., as Co-Global Syndication Agents, BNP Paribas and Harris Nesbitt Financing, Inc., as Co-U.S. Documentation Agents, and JPMorgan Chase Bank, as Global Administrative Agent, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2004 (File No. 001-13515).
4.10	First Amendment to U.S. Amended and Restated Credit Agreement, dated effective as of October 19, 2005, among Forest Oil Corporation, each of the lenders that is a party thereto, Bank of America, N.A. and Citibank, N.A., as Co-Global Syndication Agents, BNP Paribas and Harris Nesbitt Financing, Inc., as Co-U.S. Documentation Agents, Bank of Montreal and The Toronto-Dominion Bank, as Co-Canadian Documentation Agents, JPMorgan Chase

Exhibit Number	Description
	Bank, N.A., Toronto Branch, as Canadian Administrative Agent and JPMorgan Chase Bank, N.A., as Global Administrative Agent, incorporated herein by reference to Exhibit 4.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2005 (File No. 001-13515).
4.11*†	Second Amendment to the Amended and Restated Combined Credit Agreements, dated effective as of December 21, 2005, among Forest Oil Corporation, Canadian Forest Oil, each of the lenders that is party thereto, Bank of America, N.A. and Citibank, N.A., as Co-Global Syndication Agents, BNP Paribas and Harris Nesbitt Financing, Inc., as Co-U.S. Documentation Agents, and Bank of Montreal and The Toronto-Dominion Bank, as Co-Canadian Documentation Agents, JPMorgan Chase Bank, N.A., Toronto Branch, as Canadian Administrative Agent and JPMorgan Chase Bank, N.A., as Global Administrative Agent.
10.1*	Forest Oil Corporation 1996 Stock Incentive Plan and Option Agreement, incorporated herein by reference to Exhibit 4.1 to Form S-8 for Forest Oil Corporation dated June 7, 1996 (File No. 0-4597).
10.2*	First Amendment to Forest Oil Corporation 1996 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
10.3*	Second Amendment to Forest Oil Corporation 1996 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2001 (File No. 001-13515).
10.4*†	Amendment No. 3 to Forest Oil Corporation 1996 Stock Incentive Plan dated December 6, 2005.
10.5*	Forest Oil Corporation 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 4.1 to Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.6*	Amendment No. 1 to Forest Oil Corporation's 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2003 (File No. 001-13515).
10.7*	Amendment No. 2 to Forest Oil Corporation's 2001 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2004 (File No. 001-13515).
10.8*†	Amendment No. 3 to Forest Oil Corporation 2001 Stock Incentive Plan, dated January 10, 2006.
10.9*	Form of Employee Stock Option Agreement, incorporated herein by reference to Exhibit 4.2 to Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.10*	Form of Non-Employee Director Stock Option Agreement, incorporated herein by reference to Exhibit 4.3 to Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.11*	Form of Restricted Stock Agreement, incorporated herein by reference to Exhibit 10.6 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2004 (File No. 001-13515).
10.12*†	Form of Restricted Stock Agreement.

Exhibit Number	Description
10.13*	Form of Amended Grandfathered SVP Severance Agreement, incorporated herein by reference to Exhibit 10.1 to Form 8-K dated June 10, 2005 (File No. 001-13515).
10.14*	Form of Amended SVP Severance Agreement, incorporated herein by reference to Exhibit 10.2 to Form 8-K dated June 10, 2005 (File No. 001-13515).
10.15*	Form of Amended Grandfathered VP Severance Agreement, incorporated herein by reference to Exhibit 10.3 to Form 8-K dated June 10, 2005 (File No. 001-13515).
10.16*	Form of Amended VP Severance Agreement, incorporated herein by reference to Exhibit 10.4 to Form 8-K dated June 10, 2005 (File No. 001-13515).
10.17*	Forest Oil Corporation Pension Trust Agreement dated as of January 1, 2002 by and between Forest Oil Corporation and the trustees named therein or their successors, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2002 (File No. 001-13515).
10.18*	First Amendment to Forest Oil Corporation Pension Trust Agreement as Amended and Restated January 1, 2002, effective as of May 10, 2005, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2005 (File No. 001-13515).
10.19*	Forest Oil Corporation Amended and Restated Salary Deferral Compensation Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2003 (File No. 001-13515).
10.20*	Forest Oil Corporation 2005 Salary Deferred Compensation Plan, effective as of December 31, 2004, incorporated herein by reference to Exhibit 10.24 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2004.
10.21*†	Forest Oil Corporation Amended and Restated 2005 Salary Deferred Compensation Plan, effective as of December 31, 2004.
10.22*†	First Amendment to the Forest Oil Corporation Amended and Restated Salary Deferral Compensation Plan, effective as of December 31, 2005.
10.23*	Forest Oil Corporation Change of Control Deferred Compensation Plan, incorporated herein by reference to Exhibit 10.18 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2002 (File No. 001-13515).
10.24*	Forest Oil Corporation Executive Deferred Compensation Plan, effective as of July 1, 1994, incorporated herein by reference to Exhibit 10.24 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2003 (File No. 001-13515).
10.25*	First Amendment to Forest Oil Corporation Executive Deferred Compensation Plan dated November 13, 2002, incorporated herein by reference to Exhibit 10.20 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2002 (File No. 001-13515).
10.26*	Second Amendment to Forest Oil Corporation Executive Deferred Compensation Plan dated February 3, 2003, incorporated herein by reference to Exhibit 10.21 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2002 (File No. 001-13515).
10.27*†	Third Amendment to Forest Oil Corporation Executive Deferred Compensation Plan dated December 20, 2005.
10.28*	Forest Oil Corporation 2005 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation filed on March 1, 2005.

Exhibit Number	Description
10.29	Agreement and Plan of Merger dated as of September 9, 2005 among Forest Oil Corporation, SML Wellhead Corporation, Mariner Energy, Inc. and MEI Sub, Inc., incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2005 (No. 001-13515).
10.30	Tax Sharing Agreement between Forest Oil Corporation, SML Wellhead Corporation and Mariner Energy, Inc., dated as of September 9, 2005, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2005 (File No. 001-13515).
10.31	Transition Services Agreement, dated as of September 9, 2005, between Forest Oil Corporation and SML Wellhead Corporation, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2005 (File No. 001-13515).
10.32	Employee Benefits Agreement, dated as of September 9, 2005, between Forest Oil Corporation and SML Wellhead Corporation, incorporated herein by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2005 (File No. 001-13515).
10.33	Distribution Agreement, dated as of September 9, 2005, between Forest Oil Corporation and SML Wellhead Corporation, incorporated herein by reference to Exhibit 10.5 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2005 (File No. 001-13515).
21.1†	List of Subsidiaries of Registrant.
23.1†	Consent of KPMG LLP.
23.2†	Consent of Ryder Scott Company, L.P.
23.3†	Consent of DeGolyer and MacNaughton.
24.1†	Powers of Attorney (included on the signature pages hereof).
31.1†	Certification of Principal Executive Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Act of 1934.
31.2†	Certification of Principal Financial Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Act of 1934.
32.1**	Certification of Chief Executive Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.
32.2**	Certification of Chief Financial Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.

* Contract or compensatory plan or arrangement in which directors and/or officers participate.

** Not considered to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

† Indicates Exhibits filed with this Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: March 14, 2006

FOREST OIL CORPORATION
(Registrant)

By: /s/ H. CRAIG CLARK

H. Craig Clark
President and Chief Executive Officer

Power of Attorney

The officers and directors of Forest Oil Corporation, whose signatures appear below, hereby constitute and appoint H. Craig Clark, David H. Keyte, Cyrus D. Marter IV, and Victor A. Wind and each of them (with full power to each of them to act alone), the true and lawful attorney-in-fact to sign and execute, on behalf of the undersigned, any amendment(s) to this Form 10-K Annual Report for the year ended December 31, 2005, and any instrument or document filed as part of, as an exhibit to or in connection with any amendment, and each of the undersigned does hereby ratify and confirm as his own act and deed all that said attorneys shall do or cause to be done by virtue thereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ H. CRAIG CLARK H. Craig Clark	President and Chief Executive Officer and Director (Principal Executive Officer)	March 14, 2006
/s/ DAVID H. KEYTE David H. Keyte	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 14, 2006
/s/ VICTOR A. WIND Victor A. Wind	Corporate Controller (Principal Accounting Officer)	March 14, 2006
/s/ FORREST E. HOGLUND Forrest E. Hoglund	Chairman of the Board of Directors	March 14, 2006

Signatures	Title	Date
/s/ WILLIAM L. BRITTON William L. Britton	Director	March 14, 2006
/s/ CORTLANDT S. DIETLER Cortlandt S. Dietler	Director	March 14, 2006
/s/ DOD. A. FRASER Dod. A. Fraser	Director	March 14, 2006
/s/ JAMES H. LEE James H. Lee	Director	March 14, 2006
/s/ JAMES D. LIGHTNER James D. Lightner	Director	March 14, 2006
/s/ PATRICK R. MCDONALD Patrick R. McDonald	Director	March 14, 2006

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Additional Information

PRINCIPAL OFFICE

HEADQUARTERS
707 Seventeenth Street, Suite 3600
Denver, Colorado 80202
303.812.1400

INDEPENDENT RESERVE ENGINEERS

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244
214.368.6391

Ryder Scott Company
1100 Louisiana, Suite 3800
Houston, Texas 77002-5218
713.651.9191

INDEPENDENT AUDITORS

KPMG LLP
707 Seventeenth Street, Suite 2700
Denver, Colorado 80202
303.296.2323

STOCK

Common Stock Listed and Traded on:
The New York Stock Exchange
NYSE Symbol – FST

TRANSFER AGENT AND REGISTRAR FOR COMMON STOCK

Mellon Investor Services LLC
480 Washington Blvd.
Jersey City, New Jersey 07310-1900
800.635.9270

TDD for Hearing Impaired: 800.231.5469
Foreign Shareholders: 201.680.6578
TDD Foreign Shareholders: 201.680.6610
www.melloninvestor.com

INVESTOR RELATIONS

Additional information, including an Investor Package, may be obtained from:
Forest Oil Corporation
Patrick J. Redmond, Director – Investor Relations
707 Seventeenth Street, Suite 3600
Denver, Colorado 80202
InvestorRelations@forestoil.com or visit our website at
www.forestoil.com

ANNUAL MEETING OF SHAREHOLDERS

The annual meeting of shareholders of
Forest Oil Corporation will be held at the
Marriot Denver City Center
1701 California Street
Denver, Colorado 80202
Wednesday, May 10, 2006 at 9:00 a.m. MT

NEW YORK STOCK EXCHANGE CERTIFICATION

The certification of the Chief Executive Officer required by the New York Stock Exchange, relating to Forest's compliance with the New York Stock Exchange Corporate Governance Listing Standards, was submitted to the New York Stock Exchange on June 8, 2005.

NON-GAAP FINANCIAL MEASURES AND OTHER EXPLANATIONS *($ in millions)*

	2005	2004	2003
Net Debt			
Total principal long-term debt	$ 854	852	897
Less: Cash and cash equivalents	7	55	12
Net debt	847	797	885
Total shareholder's equity	1,685	1,472	1,186
Capitalization	$ 2,532	2,269	2,071
Net debt to capitalization ratio	33%	35%	43%

Reserve Ratio

Remainco's production replacement ratio of 281% was calculated by dividing the sum of additions to estimated proved oil and gas reserves during 2005, which sum equals 278 Bcfe, as determined, by Remainco's 2005 production of 99 Bcfe.

FD&A Costs

Remainco's FD&A cost of $2.16 was calculated by dividing the sum of total exploration and development and acquistion costs (excluding tax step-up in booked fair value), which sum equals $600 million, by Remainco's total reserve additions of 278 Bcfe.

*Purchase Price

Purchase price includes original unadjusted cash consideration and debt assumed in connection with the acquistion and is not equal to the purchase price recorded in purchase accounting.

FORWARD-LOOKING STATEMENTS

This report 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. Please see Item 1, header "Forward-Looking Statements" in Forest's 2005 10-K for additional disclosures.

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