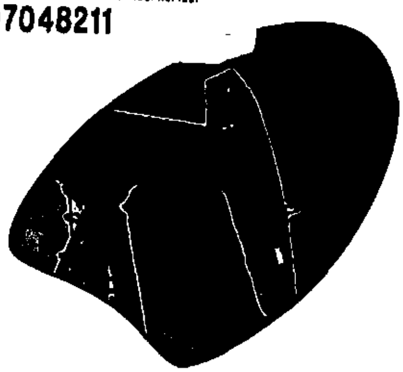
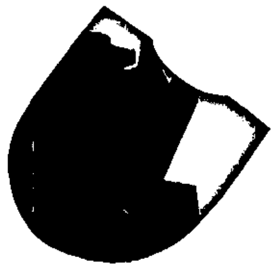
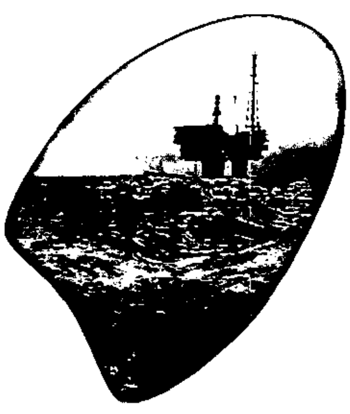
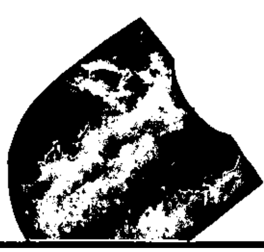
P.E 12/31/06 ARS 1-13515

TAKING THE NEXT STEP







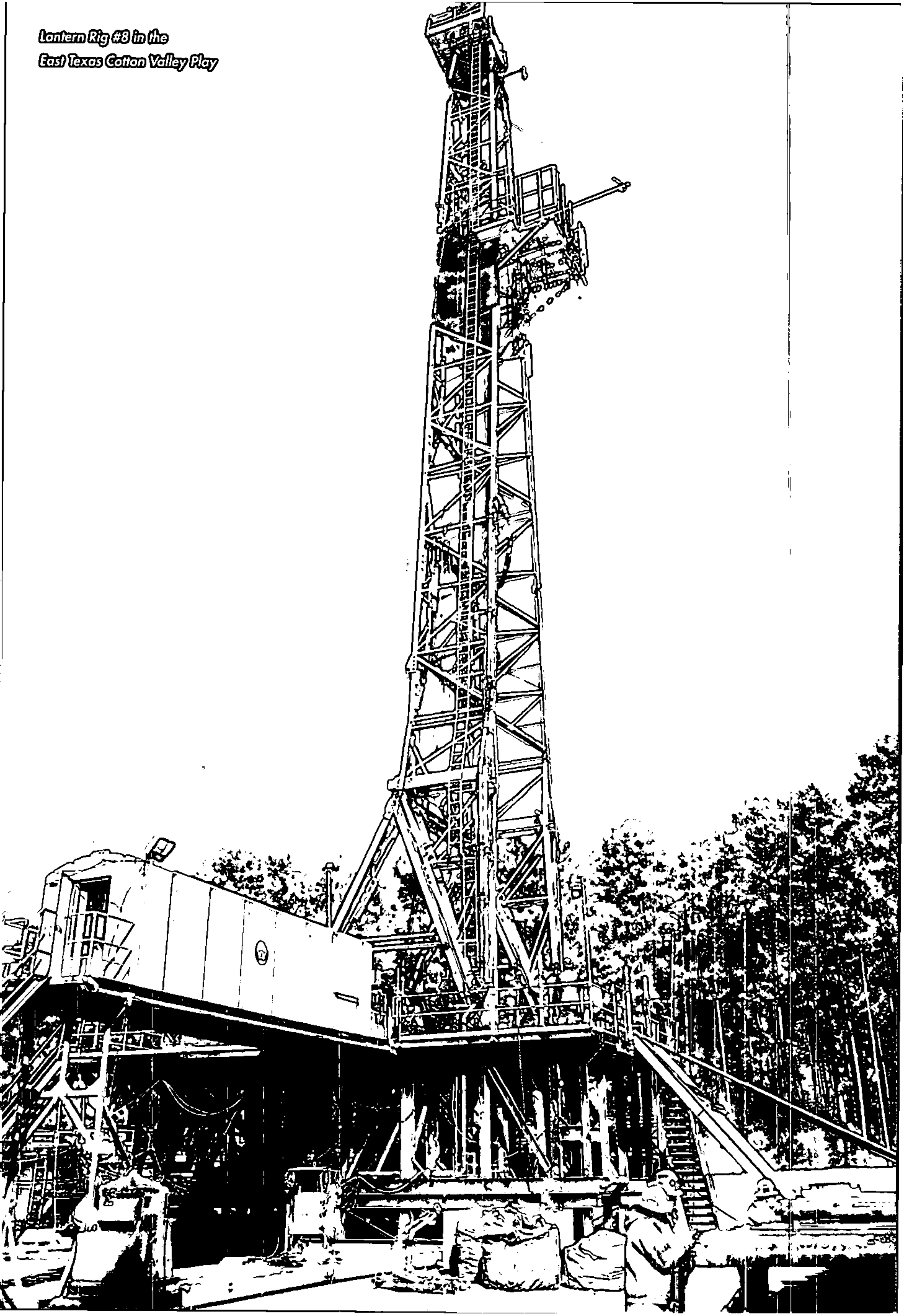


FOREST 1916 OIL

ANNUAL REPORT 2006

OVER THE PAST THREE YEARS WE HAVE SUCCESSFULLY COMPLETED THE TRANSITION FROM A GULF OF MEXICO PRODUCER WITH FRONTIER EXPLORATION EMPHASIS TO A NORTH AMERICAN ONSHORE PRODUCER WITH NUMEROUS REPEATABLE, LOW-RISK OPPORTUNITIES FOR GROWTH. WE HAVE EXECUTED OUR 4-POINT STRATEGY TO THE LETTER AND INITIATED A SERIES OF CHANGES AND STRATEGIC TRANSACTIONS THAT HAVE RESHAPED OUR PORTFOLIO. AS FOREST TAKES THE NEXT STEP TO FURTHER OUR GROWTH STRATEGY, WE WILL STEADFASTLY MAINTAIN OUR COMMITMENT TO OUR SHAREHOLDERS AND CONTINUE TO EXERCISE DISCIPLINE IN OUR CHOICES AND INVESTMENTS.

Lantern Rig #8 in the
East Texas Cotton Valley Play



Taking The Next Step

DEAR FELLOW SHAREHOLDERS

2006 will be remembered as a great year for Forest Oil, not just in numbers, but a year of transformation that established a platform for future growth. Several of the major highlights are noted on the opposite page. As our annual report cover illustrates, our team continues to take action to create shareholder value by building this Company "a step at a time." It is appropriate that taking steps is synonymous with taking action because we will never stand still or become complacent. We are always looking for ways to add shareholder value. There were many examples of this in 2006, most notably our exit from the Gulf of Mexico in a tax-efficient manner followed by a direct distribution of the proceeds to our shareholders in the form of Mariner stock. While taking the step away from the Gulf of Mexico, we simultaneously took a significant step to rebuild our Southern Business Unit with the East Texas acquisition. We subsequently took another step to improve our portfolio by creating our Alaska subsidiary with separate non-recourse financing. All of these transactions were innovative and consistent with our stated goals. And now in early 2007, we took another significant step with the pending acquisition of Houston Exploration to further strengthen our North American onshore asset base.

A few years ago, our Company's biggest challenge was to create value from the "hand we were dealt." We now have choices in our investments and within our own asset base for growth and value enhancement. Our previous goal was to have one legacy growth asset in the Company; now our goal is to have multiple growth assets within each business unit and geographic area. As we have mentioned, we strive to be the most innovative and efficient operator in these areas with a goal to be more effective than those who preceded us. Our 2006 progress in reserve replacement, production growth and cost control was very strong. We will always take steps to increase our efficiency as opposed to being a victim of industry conditions. We are proud to report that Forest essentially replaced the reserves divested from the Gulf of Mexico in 2006 with our drilling and acquisition activities. It is now easier to see the future growth potential in our assets due to the new, high quality portfolio we have assembled. It is important to note that based on the pro forma combination of the Houston Exploration assets, most of the new Company's assets did not exist three years ago when we began our work.

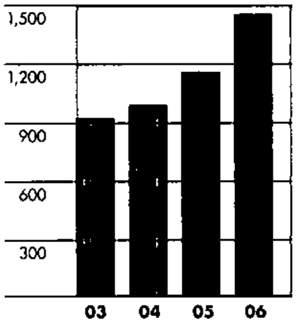
FUTURE STRATEGY

Our challenges are similar to those faced by the rest of the industry in 2007 and beyond. We may be challenged by increased costs, moderating commodity prices, tougher fiscal terms, and limited access to new resources. We have taken steps to offset these challenges, and although we are not "bullet-proof," we fared much better than most of our competition in 2006. Our early focus on controlling costs, along with our rig ownership, has served us well in the current environment. Our extensive inventory is more focused and low risk, and along with our large undeveloped acreage position provides an asset portfolio that can be exploited through a variety of market conditions. Following the closing of the Houston Exploration acquisition, our total non-proved inventory for the pro forma combined Company will be approximately 5,600 projects.

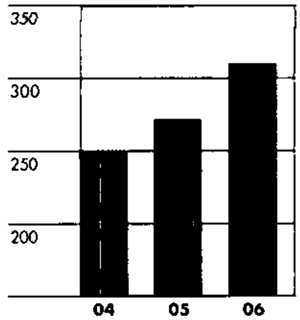
H. Craig Clark
President and CEO

Forrest E. Hoglund
Chairman of the Board

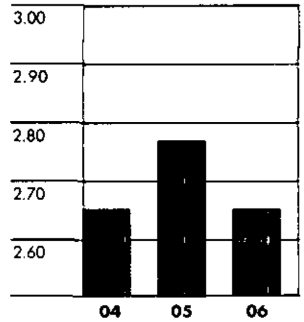
RESERVES*
(Bcfe)



PRODUCTION*
(MMcfe/d)



TOTAL CASH COSTS*
($ per Mcfe)



Pro forma for the spin-off of the Gulf of Mexico operations

2006 HIGHLIGHTS

- ***Closed spin-off of Gulf of Mexico operations***
- ***Created and separately financed our Alaska subsidiary***
- ***Rebuilt the Southern Business Unit with the East Texas acquisition***
- ***Replaced 372% of Remainco production at an all-source finding cost of $2.15/Mcfe; organic finding costs were even lower at $2.09/Mcfe***
- ***Remainco net production grew 14% while cash cost per unit decreased 4%***
- ***Company's growth was driven by "Big Four" assets, which now comprises approximately 1/3 of our production***
- ***Increased major growth areas from 6 to 13, with current project inventory of approximately 2,800 projects solely within Forest***
- ***Built large acreage positions in North America near or within existing growth plays***
- ***Negotiated pending acquisition of Houston Exploration announced in early 2007, which will increase pro forma reserves to more than 2.1 Tcfe with 18 growth areas***

Additionally, our net acreage position will move to approximately 6.5 million acres, 91% of which is undeveloped.

Our overall strategy for building an asset portfolio is to first assure ourselves that we can upgrade the portfolio with each transaction step. This was our sole purpose in the Gulf of Mexico and Alaska transactions, and now with the acquisition of Houston Exploration. Further, we intend to enhance each retained asset with continued discipline in spending and margin protection. We never buy an asset to just deplete it; our goal is to enhance or grow the value in some way. We also strongly believe that each legacy growth area should have a back-up asset to take its place as that growth area matures. Forest, in fact, has several replacement growth projects waiting in the "up and comer" category to take over or augment our "Big Four" growth areas. This ensures our Company's growth for many, many years to come. Our Company has now evolved from the assets contained in the "hand we were dealt" to a robust group of growth assets.

Our Company and employees received several awards in 2006 to recognize their entrepreneurship and deal acumen. Our employees deserve all of the credit and should also be commended for their hard work and accomplishments over the past three years, particularly in 2006. We are excited to welcome the Houston Exploration employees to our team in 2007. We would like to personally thank Cort Dietler for his past Board service and guidance through our Company's transformation these past several years. Cort has elected not to stand for reelection in 2007 and will be deeply missed. We also want to welcome Loren Carroll to the Forest Board. His business background and perspective from the oilfield service sector will prove invaluable to our Board of Directors.

Thanks to all of the shareholders and partners for their support and confidence as we prepare to take the next steps in enhancing your value. We are very proud of the Company we have created.

FORREST E. HOGLUND
Chairman of the Board

H. CRAIG CLARK
President and CEO

Operations

Prior to the close of The Houston Exploration Company acquisition, Forest has four strategic growth areas in its portfolio that will drive 2007's forecasted production growth. These areas are the Greater Buffalo Wallow Area in the Panhandle of Texas; the Wild River Field in the Deep Basin of Alberta, Canada; the Cotton Valley Play in East Texas and the newly operated Katy Field outside of Houston. Each of these properties entails large scale, low-risk, repeatable drilling programs which we believe can drive production growth for the Company and generate cash flow to Forest.

GREATER BUFFALO WALLOW AREA

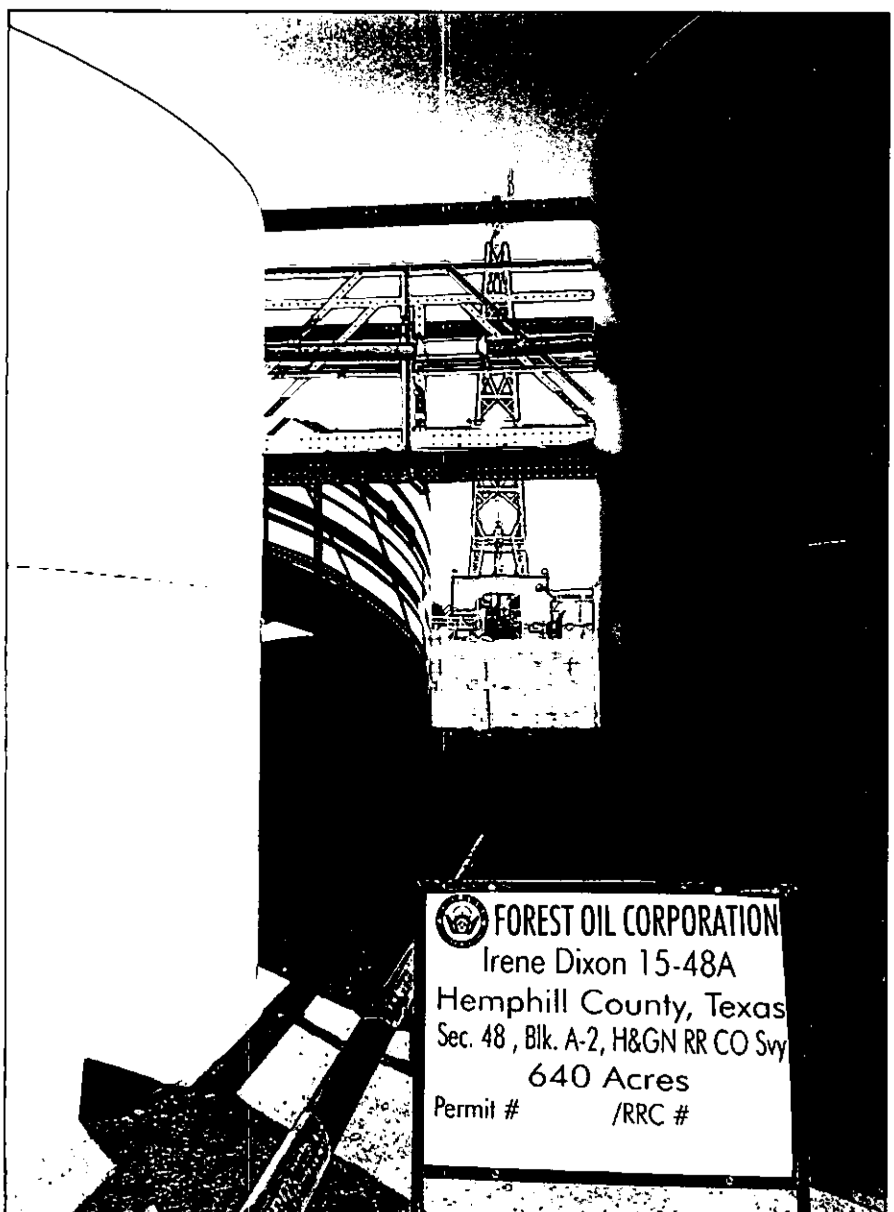
4Q 2006 Production Exit Rate (MMcfe/d)	40
4Q 2005 - 4Q 2006 Production Growth (%)	18
Total number of locations	739
Total locations to drill in 2007	54
Total number of rig years	62

Production grew to 40 MMcfe/d in the fourth quarter of 2006 in the Greater Buffalo Wallow Area. Overall production has increased 100% since the close of the acquisition in April 2005 when production was 20 MMcfe/d. For the entire field, Forest is drilling wells that include 3 to 4 fracs per well on a drilling inventory comprising approximately 62 rig years. Forest anticipates utilizing 5 rigs in 2007 to drill in the Greater Buffalo Wallow Area and anticipates gross initial production rates to average 3.1 MMcfe/d per well. Blocking and tackling on our large project inventory will be the order for the Greater Buffalo Wallow Area in 2007.

WILD RIVER FIELD

4Q 2006 Production Exit Rate (MMcfe/d)	37
4Q 2005 - 4Q 2006 Production Growth (%)	48
Total number of locations	58
Total locations to drill in 2007	30
Total number of rig years	5

Arguably the best performer in Forest's portfolio, production at Wild River has grown to 37 MMcfe/d in the fourth quarter of 2006, a 48% increase from the fourth quarter of 2005 and a 311% increase from the 9 MMcfe/d the field was producing when Forest initiated a large scale multiple rig drilling program in the fourth quarter of 2004. With 58 future drilling locations, the field has a drilling inventory comprising approximately 5 rig years. Gross initial production rates are expected to average 2.3 MMcfe/d per well in 2007 as a result of new frac techniques being employed in the field. In addition, these new frac techniques have decreased our average completion cost per well by 33%. The primary goals for 2007 include continued enhancement of initial production rates through additional frac technique improvements and the implementation of studies to identify opportunities to downspace the field.



The photo at left depicts the repeatability of our operations in the Greater Buffalo Wallow Area. Once a well is drilled, the rig steps off to the next location while the well is completed and put on production.

Forest drilled 31 wells in 2006 in East Texas and plans to drill another 36 wells in 2007 with a two-rig program.

COTTON VALLEY PLAY

4Q 2006 Production Exit Rate (MMcfe/d)	21
From acquisition - 4Q 2006 Production Growth (%)	62
Total number of locations	349
Total locations to drill in 2007	36
Total number of rig years	22

In March 2006, Forest closed its acquisition of assets located primarily in the Cotton Valley Play, paying approximately $255 million for 110 Bcfe of proved reserves and production averaging 13 MMcfe/d. Since the time of the acquisition, production has increased 62% to 21 MMcfe/d in the fourth quarter of 2006. Our better-than-anticipated production was achieved through accelerated drilling and frac optimization. Forest has a drilling inventory consisting of approximately 22 rig years, or a total of approximately 349 future drilling locations. Gross initial production rates are expected to average approximately 1.2 MMcfe/d per well. In 2007, Forest intends to drill a horizontal well in Harrison County, targeting a member of the lower Cotton Valley sand. With analysis of the results from this well, Forest will evaluate an increased scale, horizontal development program.

KATY FIELD

4Q 2006 Production Exit Rate (MMcfe/d)	20
August 1, 2006 - 4Q 2006 Production Growth (%)	54
Total number of projects	24
Total locations to drill in 2007	4

Effective August 1, 2006, Forest took over complete operatorship of the Katy Field. At that time Forest initiated a program to study 131 wells in the field, both shut-in and producing; previous gross production was 13 MMcfe/d. Since August 2006, gross production in the field has increased by 54% to 20 MMcfe/d. The Sparks/Wilcox and Frio sands are expected to yield average gross initial production rates of 1.5 MMcfe/d and 1.0 MMcfe/d, respectively. 2007 will see a significant increase in activity in the field with work ranging from drilling new wells to shallow recompletion work to surface facilities focusing on increasing production.

KEY GROWTH AREA	GROSS PROJECT INVENTORY*		NET UNRISKED POTENTIAL (BCFE)*	
	FST	THX	FST	THX
GREATER BUFFALO WALLOW AREA	656	–	722	–
CANADA DEEP BASIN AND FOOTHILLS	153	–	102	–
ARK-LA-TEX	246	605	158	224
SOUTH TEXAS	21	395	74	349
BARNETT SHALE	119	–	129	–
PERMIAN	1,237	–	622	–
ROCKIES**/NIOBRARA	352	1,811	55	492
TOTAL	2,784	2,811	1,862	1,065

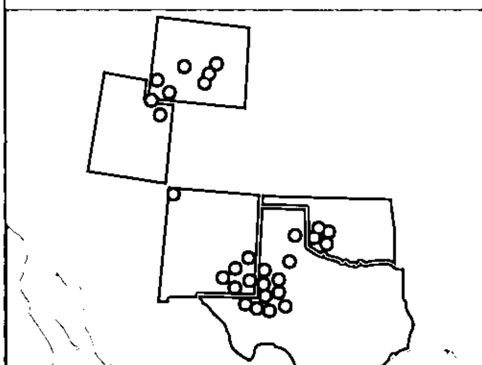
* Does not include currently booked gross project inventory or estimated proved reserves
**Does not include THX Uinta gross project inventory or net unrisked potential (Bcfe)

Note: Rig years is defined as the total number of locations for each play divided by the average number of wells one rig could drill in one year in that respective play.

Operational Fact Sheet

Western

	2006	2005	2004
NET PRODUCTION			
Gas (MMcf/d)	71.0	58.7	46.5
Liquids (MBbls/d)	10.2	9.4	6.8
ESTIMATED PROVED RESERVES			
Gas (Bcf)	339.0	367.1	252.9
Liquids (MMBbls)	60.9	52.3	44.9
Equivalent (Bcfe)	704.1	680.9	522.8
DEVELOPED ACREAGE			
Gross	262,461	274,881	232,080
Net	154,267	157,556	131,602
UNDEVELOPED ACREAGE			
Gross	207,190	197,206	179,529
Net	103,820	97,678	100,091
GROSS WELL COUNT			
Gas	3,091	3,655	2,941
Oil	2,674	2,661	2,735
CAPITAL EXPENDITURES In thousands			
	$299,398	$492,123	$258,352



2006 HIGHLIGHTS

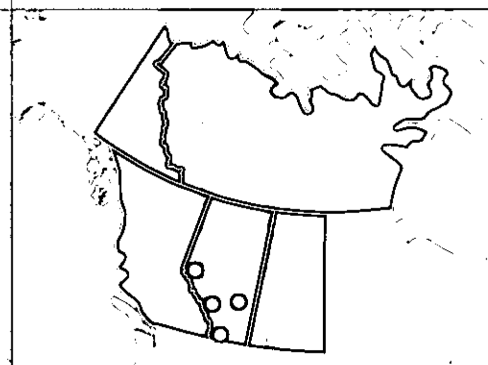
- Increased reserves 3% to 704 Bcfe at an all-in reserve replacement ratio of 171%
- Increased production 15% to 132 MMcfe/d in 2006 from 115 MMcfe/d in 2005
- Record production of 40 MMcfe/d in the Greater Buffalo Wallow Area
- 100% success rate in the Greater Buffalo Wallow Area with IP's averaging 3.2 MMcfe/d due to improved technologies, utilization of slick-water fracs and deeper pay completions
- Added 12,300 acres in the Greater Buffalo Wallow Area increasing total gross acreage to 45,400 acres
- Continued program in the Fusselman, Atoka and Morrow sands in the Greater Vermejo/Haley Area
- Added 15,500 acres at Greater Vermejo/Haley increasing total gross acreage to 45,700 acres
- Total of 21 wells drilled with a 100% success rate in the Central Midland Basin
- Utilized Forest owned and operated Lantern Drilling rigs

FUTURE STRATEGY

- 2007 drilling program calls for 289 wells and a continued high pace of additional projects
- Plan to drill approximately 54 wells in the Greater Buffalo Wallow Area with a total of 739 future locations identified
- Process and interpret seismic related to the Greater Vermejo/Haley Area in 2007 while maintaining a one rig program
- Plan to drill approximately 21 wells in the Central Midland Basin with a total of 1,200 future locations identified
- Continue to leverage on the Lantern Drilling rigs as a tool to keep costs in check

Canada

	2006	2005	2004
NET PRODUCTION			
Gas (MMcf/d)	66.7	51.8	43.6
Liquids (MBbls/d)	3.1	3.4	3.5
ESTIMATED PROVED RESERVES			
Gas (Bcf)	197.9	141.5	117.5
Liquids (MMBbls)	5.7	5.0	5.8
Equivalent (Bcfe)	232.1	171.5	152.1
DEVELOPED ACREAGE			
Gross	267,157	236,678	185,369
Net	151,645	136,837	103,964
UNDEVELOPED ACREAGE			
Gross	1,082,504	1,118,462	1,378,226
Net	581,746	598,481	826,340
GROSS WELL COUNT			
Gas	572	515	471
Oil	329	323	316
CAPITAL EXPENDITURES In thousands			
	$150,955	$115,019	$158,310



2006 HIGHLIGHTS

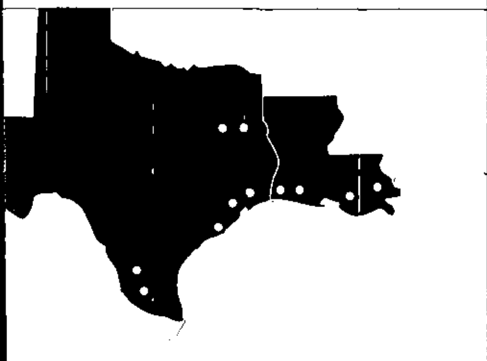
- Increased reserves 35% to 232 Bcfe at an all-in reserve replacement ratio of 294%
- Increased production 18% to 85 MMcfe/d in 2006 from 72 MMcfe/d in 2005
- Continued exploitation strategy in the Wild River Field with a production increase of 48% to a record 37 MMcfe/d in the fourth quarter of 2006 from 25 MMcfe/d in the fourth quarter of 2005
- 100% success rate with IP's in the Wild River Field averaging 2.5 MMcfe/d as a result of new frac techniques being employed in the field
- Successfully drilled 11 wells in the Sundance/Ansell Area
- Completed Waterton well in the first quarter of 2006 that produced a gross rate of 12–14 MMcfe/d in the fourth quarter of 2006

FUTURE STRATEGY

- 2007 drilling program calls for 60 wells and a continued high pace of additional projects
- Plan to drill approximately 30 wells in the Wild River Field with a total of 58 future locations identified
- Continue with exploration efforts in the Sundance/Ansell Area, drilling 7–10 wells in 2007, with the intent to develop the area into a large scale multiple rig drilling program

Southern

	2006	2005	2004
NET PRODUCTION			
Gas (MMcf/d)	36.2	27.7	34.7
Liquids (MBbls/d)	3.0	2.7	3.2
ESTIMATED PROVED RESERVES			
Gas (Bcf)	232.4	125.2	140.2
Liquids (MMBbls)	17.6	10.1	9.6
Equivalent (Bcfe)	338.1	185.8	197.6
DEVELOPED ACREAGE			
Gross	184,475	101,554	94,415
Net	102,385	59,118	57,272
UNDEVELOPED ACREAGE			
Gross	252,482	259,310	208,688
Net	124,252	122,583	90,093
GROSS WELL COUNT			
Gas	441	344	322
Oil	345	165	129
CAPITAL EXPENDITURES In thousands			
	$412,803	$39,645	$70,392



2006 HIGHLIGHTS

- Increased reserves 82% to 338 Bcfe at an all-in reserve replacement ratio of 867%
- Increased production 25% to 55 MMcfe/d in 2006 from 44 MMcfe/d in 2005
- Acquired 110 Bcfe of proved reserves and 13 MMcfe/d of production in the Cotton Valley Play of East Texas for $255 million in March 2006
- Continued exploitation strategy in the Cotton Valley Play with a production increase of 62% to 21 MMcfe/d in the fourth quarter of 2006 from 13 MMcfe/d at the time of the acquisition
- Took over complete operations in the Katy Field drilling seven Frio wells *in the fourth quarter* of 2006 and commenced a field study for recompletion and workover candidates
- Entered into a 50/50 joint venture in the Barnett Shale to accelerate drilling operations and expand gross acreage position

FUTURE STRATEGY

- 2007 drilling program calls for 52 wells and a continued high pace of additional projects
- Plan to drill approximately 36 wells in the Cotton Valley Play with a total of 349 future locations identified
- Forest Texas Gathering Company was created to build out gathering lines in the Cotton Valley Play to enhance recoveries and lower cost
- Forest anticipates a nine well Wilcox recompletion/re-entry program in the Katy Field
- Plan to shoot and process over 130 square miles of 3D seismic by mid-2007 at Sabine
- Delineation of Barnett Shale acreage with 4-6 wells planned in 2007

Alaska

	2006	2005	2004
NET PRODUCTION			
Gas (MMcf/d)	8.7	6.4	–
Liquids (MBbls/d)	4.9	5.8	7.3
ESTIMATED PROVED RESERVES			
Gas (Bcf)	8.7	19.7	16.8
Liquids (MMBbls)	28.7	17.2	16.8
Equivalent (Bcfe)	180.9	122.8	117.5
DEVELOPED ACREAGE			
Gross	52,242	308,284	301,990
Net	32,155	34,029	31,124
UNDEVELOPED ACREAGE			
Gross	1,038,532	1,425,943	1,380,538
Net	1,012,637	1,196,061	1,150,656
GROSS WELL COUNT			
Gas	11	4	3
Oil	140	1,644	1,644
CAPITAL EXPENDITURES In thousands			
	$33,585	$20,437	$21,928

2006 HIGHLIGHTS

- Initiated and completed field studies which resulted in increased reserves and project inventory
- Created Forest Alaska Operating LLC and successfully placed non-recourse financing to monetize $350 million of cash flow from the Alaska oil assets to allow for the deployment of capital to other areas of Forest

FUTURE STRATEGY

- Divestiture of Alaska subsidiary planned in 2007

International

	2006	2005	2004
ITALY: UNDEVELOPED ACREAGE			
Gross	654,896	756,857	756,857
Net	654,014	755,975	756,857
WEST AFRICA: UNDEVELOPED ACREAGE			
Gross	5,180,971	5,180,971	7,184,101
Net	2,679,180	2,438,252	3,890,776
CAPITAL EXPENDITURES In thousands			
	$6,984	$3,688	$5,755

2006 HIGHLIGHTS

- Submitted Ibhubesi Plan of Development and Ibhubesi Production Right application to the South Africa Petroleum Agency
- Preparations for the drilling of Monte Pallano-1 (Bomba Field) in Italy
- In Gabon, acquisition of 3D seismic survey, fully carried by partner

FUTURE STRATEGY

- Continue progress in securing Ibhubesi Production Right and associated gas contracts in South Africa
- Evaluate 3D seismic data acquired on Gabon acreage to determine future drilling locations
- Divestiture of Italy and Australia assets

Executive Officers

H. CRAIG CLARK, 50
President and Chief Executive Officer
Years of Service: 6

DAVID H. KEYTE, 50
Executive Vice President and
Chief Financial Officer
Years of Service: 19

CECIL N. COLWELL, 56
Senior Vice President –
Worldwide Drilling
Years of Service: 18

LEONARD C. GURULE, 50
Senior Vice President – Alaska
Years of Service: 4

J.C. RIDENS, 51
Senior Vice President – Southern Region
Years of Service: 3

R. SCOT WOODALL, 45
Senior Vice President – Western Region
Years of Service: 7

MATTHEW A. WURTZBACHER, 44
Senior Vice President –
Corporate Planning and Development
Years of Service: 8

CYRUS "SKIP" D. MARTER IV, 43
Vice President, General Counsel
and Secretary
Years of Service: 5

VICTOR A. WIND, 33
Corporate Controller
Years of Service: 2

Board of Directors

WILLIAM L. BRITTON, age 72, has been a director since 1996. Mr. Britton is Chairman Emeritus of 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 of ATCO Ltd., Canadian Utilities Limited and CU Inc. He is a director of Barking Power Limited, Akita Drilling Ltd. and The Denver Broncos Football Club. He is Chairman of Hanzell Vineyards, Ltd., and Geary-Market Investment Company of California. He is a member of our Nominating and Corporate Governance Committee.

LOREN K. CARROLL, age 63, has been a director since November 2006. Mr. Carroll served as President and Chief Executive Officer of M-I SWACO, a fluid engineering services company controlled by Smith International, Inc., and as Executive Vice President of Smith International, Inc., a supplier of products and services to the oil and gas, petrochemical, and other industrial markets until his retirement in April 2006. He initially joined Smith International in December 1984 as Vice President and Chief Financial Officer and served as Executive Vice President and Chief Financial Officer during 1988 and 1989. Mr. Carroll rejoined Smith International in 1992 as Executive Vice President and Chief Financial Officer. Mr. Carroll also serves as a director of Smith International, Inc., Fleetwood Enterprises, Inc., a producer of recreational vehicles and manufactured homes, and CGG-Veritas, a geophysical services and equipment company. Mr. Carroll is a member of our Compensation Committee and Nominating and Corporate Governance Committee.

CORTLANDT S. DIETLER, age 85, 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 and Cimarex Energy Co., which are oil and gas exploration and production companies. He is the Chairman of our Nominating and Corporate Governance Committee and is a member of our Compensation Committee.

DOD A. FRASER, age 56, 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 73, 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 Maritime Corp., a natural gas transportation company, since December 2004. Mr. Hoglund has served as Chairman and Chief Executive Officer of Arctic 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 58, 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 and exploration 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 our Executive Committee.

JAMES. D. LIGHTNER, age 54, has been a director since 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 and Cornerstone E&P Company LP, a private oil and gas exploration and production company. He is the Chairman of our Compensation Committee.

PATRICK R. MCDONALD, age 49, has been a director since 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.

H. CRAIG CLARK, age 50, 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. 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 Pro Energy, an affiliate of Apache. Mr. Clark is a member of our Executive Committee.

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, 2006

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, 2006, the last business day of the registrant's most recently completed second fiscal quarter, was $1,808,671,247 (based on the closing price of such stock on the New York Stock Exchange Composite Tape).

There were 63,009,959 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 16, 2007.

Documents incorporated by reference: Portions of the registrant's notice of annual meeting of shareholders and proxy statement to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end of December 31, 2006 are incorporated by reference into Part III of this Form 10-K.

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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 three geographical segments and five business units. Geographical segments include: the United States, Canada and International. Business units include: the Western United States ("Western"), Southern United States ("Southern"), Alaska, Canada and International. We conduct exploration and development activities in each of our geographical segments; 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, 2006, approximately 84% of our estimated proved oil and gas reserves were in the United States and approximately 16% were in Canada. Forest's total estimated proved reserves as of December 31, 2006 were 1,455 Bcfe.

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.

Pending Acquisition of Houston Exploration

On January 7, 2007, Forest announced it had entered into a definitive agreement and plan of merger pursuant to which The Houston Exploration Company ("Houston Exploration") will merge with and into Forest in a stock and cash transaction totaling approximately $1.5 billion plus the assumption of debt. Houston Exploration is an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America with operations in the following four producing areas in the United States: South Texas, East Texas, the Arkoma Basin of Arkansas, and the Uinta and DJ Basins in the Rocky Mountains. The boards of directors of Forest and Houston Exploration have each unanimously approved the transaction. The transaction is subject to regulatory approvals and other customary conditions, as well as both Forest shareholder and Houston Exploration stockholder approvals. Forest management and its board of directors will continue in their current positions with Forest following the completion of the merger. The merger is expected to close in the second quarter of 2007.

Under the terms of the merger agreement, Houston Exploration stockholders are to receive total consideration equal to 0.84 shares of Forest common stock and $26.25 in cash for each share of Houston Exploration common stock outstanding. This represents estimated merger consideration of 23.6 million shares of Forest common stock and cash of approximately $740 million, or $52.47 per share, to be received by the Houston Exploration stockholders (based on the closing price of Forest's common stock on January 5, 2007 and the number of shares of Houston Exploration common stock outstanding on January 4, 2007 and subject to increase in the event that any additional shares of Houston Exploration common stock are issued prior to the merger closing date in connection with the exercise of outstanding stock options pursuant to the terms of the merger agreement). The actual amount of total cash and stock consideration to be received by each Houston Exploration stockholder will be determined by elections, an equalization formula and a proration procedure. It is anticipated that the transaction will be tax free to Houston Exploration and the stock portion of the consideration will be received tax free by its stockholders. The cash component of the acquisition is expected to be financed under an amended and restated revolving credit facility of up to $1.4 billion for which JPMorgan Chase Bank, N.A. has provided us a commitment letter.

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 stock dividend, which consisted of a pro rata spin-off (the "Spin-off") of all outstanding shares of Forest Energy Resources, Inc. (hereinafter known as Mariner Energy Resources, Inc. or "MERI"), 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, MERI was merged with a subsidiary of Mariner Energy, Inc. ("Mariner") (the "Merger"). Mariner's common stock 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 dividend of 0.8093 shares of MERI for each outstanding share of Forest common stock. In the Merger, Forest shareholders received one share of Mariner common stock for each whole share of MERI that they held. The Spin-off was a tax-free transaction for federal income tax purposes.

Business Strategy

Our strategy includes four key points: to provide organic growth, make strategic acquisitions, control costs, and remain financially flexible.

Organic Growth

The acquisitions of The Wiser Oil Company in 2004, the Buffalo Wallow field in 2005, and the East Texas Cotton Valley assets in 2006 provide, and we also expect the proposed acquisition of Houston Exploration to provide, assets conducive to low-risk, repeatable development and exploitation opportunities. In 2007, Forest expects organic growth from its planned exploitation activities, including exploration and development drilling, 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 plan in 2003, through 2006, we have spent approximately $1.5 billion (including deferred tax gross ups of $151 million recorded in connection with business combinations) to acquire approximately 838 Bcfe of estimated proved reserves. In general, our acquisition program since 2004 has focused on acquisitions of properties that have substantial development drilling opportunities and undeveloped acreage.

During 2006, we made approximately $316 million of oil and gas acquisitions, including the acquisition of oil and gas properties located primarily in the Cotton Valley trend in East Texas ("Cotton Valley assets") for approximately $255 million in cash, as adjusted to reflect an economic effective date of February 2, 2006. At the time the acquisition was announced, the Cotton Valley assets included approximately 26,000 net acres, an estimated 110 Bcfe of estimated proved reserves, and production of 13 MMcfe per day. Of the 26,000 net acres, approximately 14,000 net acres were undeveloped.

During 2005, we made approximately $314 million of oil and gas acquisitions (including approximately $71 million of deferred tax gross ups). 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 and approximately 28,000 net acres primarily in Hemphill and Wheeler Counties, Texas.

During 2004, we made approximately $436 million of oil and gas acquisitions (including approximately $47 million of deferred tax gross ups). 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 and approximately 388,000 net acres.

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 are designed to generate discretionary cash flow in each of our producing business units. A critical area of our cost control efforts is lease operating expense. While in a period of rising costs in the oil and gas sector, we have successfully kept our per-unit lease operating expenses attributable to the properties retained after the Spin-off at levels near those achieved in 2004. See "*Lease Operating Expenses*" and the accompanying table on page 34. Lease operating expense attributable to the retained properties was $1.21 per Mcfe in 2006 compared to $1.19 per Mcfe in 2004.

Maintain Financial Flexibility

We seek to maintain financial flexibility and sufficient liquidity to capitalize on opportunities as they arise. Generally, we attempt to maintain a debt-to-book capitalization ratio of between 30% and 40% but may occasionally exceed this range when conditions warrant using leverage to make strategic acquisitions. At December 31, 2006, for example, our debt-to-book capitalization ratio was 46%, which was higher than our targeted ratio. The higher leverage was due to two transactions in 2006. The Spin-off, which was accounted for as a special dividend, reduced our shareholders' equity by over $500 million. In addition, we utilized our bank credit facilities in 2006 to purchase the Cotton Valley assets for $255 million as described above. Upon closing the pending acquisition of Houston Exploration, our debt-to-book capitalization ratio will likely increase to approximately 50% due primarily to the approximate $740 million of cash consideration expected to be paid and other Houston Exploration debt to be assumed. However, as discussed below, we have recently announced plans to sell our Alaska business unit in 2007 in order to reduce indebtedness. At December 31, 2006, we had approximately $33 million of cash on hand and $489 million available under our credit facilities.

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 February 27, 2007 we have hedged, via swaps and collar instruments, approximately 55 Bcfe of our 2007 production.

Business Unit Activities

The production volumes, estimated proved reserves, and capital expenditures for our business units as of and for the year ended December 31, 2006 are summarized below.

	Production				Reserves	Capital Expenditures		
Business Unit	Natural Gas (MMcf)	Oil & NGLs (MBbls)	Total (MMcfe)	Average Daily (MMcfe)	Total (Bcfe)	Exploration and Development	Property Acquisitions	Total[2]
						(In Thousands)		
Southern:								
Offshore[1]	6,378	275	8,028	22.0	—	$ 36,487	672	37,159
Onshore	13,195	1,111	19,861	54.4	338.1	120,188	292,615	412,803
Western	25,924	3,730	48,304	132.4	704.1	277,372	22,026	299,398
Alaska	3,177	1,771	13,803	37.8	180.9	33,585	—	33,585
Canada	24,350	1,139	31,184	85.4	232.1	150,955	—	150,955
International	—	—	—	—	—	6,984	—	6,984
Total	73,024	8,026	121,180	332.0	1,455.2	$625,571	315,313	940,884

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

(2) Does not include estimated discounted asset retirement obligations of $2.4 million, including $1.0 million assumed in connection with acquisition activities.

Southern

The Southern business unit's onshore operations are located in East Texas, South Texas, and Louisiana Gulf Coast. The onshore portion of the Southern business unit had a production increase of 24% in 2006 compared to 2005. Production was increased through a combination of acquisitions and exploitation, including a drilling program that totaled 56 gross wells in 2006. The Southern business unit's major capital expenditures in 2007 are expected to be primarily directed to its East Texas Cotton Valley field as well as the Katy field outside of Houston, in which the Company gained operatorship in August 2006.

Western

The Western business unit's operations are located in the Texas Panhandle, West Texas, New Mexico, western Oklahoma, Utah and Wyoming. The Western business unit had a production increase of 15% in 2006 compared to 2005 primarily due to the continued development of the Buffalo Wallow field and exploration success in the Greater Haley/Vermejo fields in Texas. In 2007, capital expenditures in this business unit are expected to be primarily targeted in the Buffalo Wallow field and the Permian Basin.

Alaska

The Alaska business unit's operations are primarily located onshore and offshore Cook Inlet. The Alaska business unit had a production decrease of 8% in 2006 compared to 2005. Production decreased due to natural declines in the non-operated offshore oil fields offset in part by increased natural gas production in 2006 from our onshore gas exploration program. Effective October 31, 2006, we transferred the majority of the assets associated with the Alaska business unit to a separate subsidiary which obtained $375 million of term loan financing that is secured by substantially all of the subsidiary's assets and is nonrecourse to Forest's other assets. See Note 4 to the Consolidated Financial Statements. In January 2007, the Company announced its plans to sell its Alaska business unit in order to reduce indebtedness associated with the pending acquisition of Houston Exploration.

Canada

The Canada business unit's operations are located primarily in Alberta and British Columbia. The Canada business unit had a production increase of 18% in 2006 compared to 2005. Production was increased through development and exploratory drilling in the Wild River, Ansell and Foothills areas in central Alberta. In 2007, capital expenditures in this business unit are expected to be directed primarily in the Wild River, Evi/Loon, Ansell, and Foothills areas.

International

The International business unit's operations are located primarily in South Africa, Gabon and Italy. In 2006, the International business unit completed the drilling of a shallow oil prospect in Gabon which was found to be dry; however, the majority of the drilling costs were carried by our partners. In South Africa, the International business unit continued to pursue commercial development of the Ibhubesi field discovery. The business unit filed a production right application and also continued efforts toward securing gas contracts for the Ibhubesi field. In 2007, the business unit plans to drill a gas test well in central Italy which was originally planned for 2006 but was delayed due to rig availability following the receipt of the drilling permit.

Reserves

The following table shows our estimated quantities of proved reserves as of December 31, 2006 and 2005. All estimated proved reserves are currently located in North America. See Note 15 to the Consolidated Financial Statements for additional information regarding estimated proved reserves.

	December 31,			
	2006	2005		
	Total	Retained Properties[1]	Spin-off Properties[1]	Total
Proved developed:				
Natural gas (MMcf)	566,139	497,213	142,143	639,356
Liquids (MBbls)	78,280	62,805	8,792	71,597
Total (MMcfe)	1,035,819	874,043	194,895	1,068,938
Proved undeveloped:				
Natural gas (MMcf)	211,900	156,328	88,999	245,327
Liquids (MBbls)	34,584	21,771	3,702	25,473
Total (MMcfe)	419,404	286,954	111,211	398,165
Total proved:				
Natural gas (MMcf)	778,039	653,541	231,142	884,683
Liquids (MBbls)	112,864	84,576	12,494	97,070
Total (MMcfe)	1,455,223	1,160,997	306,106	1,467,103

(1) "Retained Properties" refers to the properties and associated estimated proved reserves retained by Forest following the Spin-off transaction completed on March 2, 2006. The "Spin-off Properties" and associated 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 its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, as well as economic factors such as change in product prices or development and production expenses, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates. See 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 2006, we filed estimates of our oil and gas reserves as of December 31, 2005 with the DOE, which were consistent with the reserve data reported for the year ended December 31, 2005 in Note 15 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 the aggregate value of Forest's year-end proved reserves, discounted at 10% per annum, for each country in which Forest owns fields for which proved reserves have been recorded. The fields selected for audit comprise at least the top 80% of Forest's fields based on the discounted value of such fields and a minimum of 80% of the value added during the year through discoveries, extensions, and acquisitions. Forest may also include fields that fall outside of the top 80% 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%. 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 Securities and Exchange Commission ("SEC").

For the year-end 2006, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. DeGolyer and MacNaughton independently audited estimates relating to properties constituting approximately 83% of our reserves, as of December 31, 2006, based on reserve values. When compared on a field-by-field basis, some of Forest's estimates of net proved reserves were greater and some were less than the estimates prepared by DeGolyer and MacNaughton. However, there was no material difference, in the aggregate, between Forest's internal estimates of total net proved reserves and the estimates prepared by DeGolyer and MacNaughton for the fields subject to the audit.

Drilling Activities

During 2006, we drilled a total of 382 gross wells, of which 158 were classified as exploration and 224 were classified as development. Our 2006 drilling program achieved a 98% success rate. The following table summarizes the number of wells drilled during 2006, 2005, and 2004, 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, 2006, we had 27 gross (16 net) wells in progress in the United States and 18 gross (10 net) wells in progress in Canada.

	Year Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Gas wells	210	52	232	32	58	25
Oil wells	13	11	16	14	34	31
Non-productive[1]	1	1	3	3	6	5
Total	224	64	251	49	98	61
Exploratory wells, completed as:						
Gas wells	135	68	100	51	36	20
Oil wells	15	9	31	27	1	1
Non-productive[1]	8	5	10	5	9	5
Total	158	82	141	83	46	26

(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

Productive wells consist of producing wells, and wells capable of production, including shut-in wells. One or more completions in the same well bore are counted as one well. As of December 31, 2006, Forest owned interests in 410 gross wells containing multiple completions. The following table summarizes our productive wells as of December 31, 2006, 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	719	620	2,824	161	353	279	219	57	4,115	1,117
Oil	1,991	1,792	1,168	283	234	209	95	20	3,488	2,304
Total	2,710	2,412	3,992	444	587	488	314	77	7,603	3,421

(1) The large variance between gross and net non-operated wells is primarily a result of our ownership interest in approximately 2,539 gross gas wells in the San Juan Basin with an average working interest of approximately 2%.

Acreage

The following table summarizes developed and undeveloped acreage in which we owned a working interest or held an exploration license as of December 31, 2006 and 2005. 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,							
	2006				2005			
	Developed Acreage		Undeveloped Acreage		Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States:								
Southern:								
Offshore	—	—	—	—	883,340	364,509	335,992	219,446
Onshore	184,475	102,385	252,482	124,252	101,554	59,118	259,310	122,583
Western	262,461	154,267	207,190	103,820	274,881	157,556	197,206	97,678
Alaska	52,242	32,155	1,038,532	1,012,637	308,284	34,029	1,425,943	1,196,061
	499,178	288,807	1,498,204	1,240,709	1,568,059	615,212	2,218,451	1,635,768
Canada	267,157	151,645	1,082,504	581,746	236,678	136,837	1,118,462	598,481
International:								
South Africa	—	—	2,771,695	1,474,542	—	—	2,771,695	1,474,542
Gabon	—	—	2,409,276	1,204,638	—	—	2,409,276	963,710
Italy	—	—	654,896	654,014	—	—	756,857	755,975
	—	—	5,835,867	3,333,194	—	—	5,937,828	3,194,227
Total	766,335	440,452	8,416,575	5,155,649	1,804,737	752,049	9,274,741	5,428,476

At December 31, 2006, approximately 1% and 9% of our net undeveloped acreage in the United States and Canada was held under leases that have terms that will expire in 2007 and 2008, respectively, if not extended by exploration or production activities. In the first quarter of 2007, we relinquished two permits in Italy comprising 363,853 gross and net undeveloped acres. 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, average sales price, and production cost information for the years ended December 31, 2006, 2005, and 2004.

	United States			Canada			Total Company		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
Natural Gas:									
Sales price received (per Mcf)	$ 6.21	7.53	6.10	5.07	6.70	4.23	5.83	7.37	5.82
Effects of energy swaps and collars (per Mcf)[1]	(.37)	(1.24)	(.56)	—	—	—	(.25)	(1.01)	(.48)
Average sales price (per Mcf)[1]	$ 5.84	6.29	5.54	5.07	6.70	4.23	5.58	6.36	5.34
Natural gas sales volumes (MMcf)	48,674	82,912	91,420	24,350	18,921	15,946	73,024	101,833	107,366
Liquids:									
Oil and Condensate:									
Sales price received (per Bbl)	$ 62.18	52.78	39.24	50.89	41.92	35.49	60.79	51.67	38.88
Effects of energy swaps and collars (per Bbl)[1]	(4.94)	(11.22)	(7.84)	—	—	—	(4.34)	(10.07)	(7.09)
Average sales price (per Bbl)[1]	$ 57.24	41.56	31.40	50.89	41.92	35.49	56.45	41.60	31.79
Natural gas liquids:									
Average sales price (per Bbl)	$ 32.02	29.61	26.05	41.40	36.15	28.08	33.85	30.76	26.56
Total liquids:									
Average sales price (per Bbl)[1]	$ 51.22	39.12	30.75	47.56	40.04	33.25	50.70	39.23	31.05
Liquids sales volumes (MBbls)	6,887	9,316	9,550	1,139	1,252	1,287	8,026	10,568	10,837
Average sales price (per Mcfe)[1]	**$ 7.08**	**6.38**	**5.38**	**5.69**	**6.69**	**4.66**	**6.72**	**6.43**	**5.28**
Total sales volumes (MMcfe)	**89,996**	**138,808**	**148,720**	**31,184**	**26,433**	**23,668**	**121,180**	**165,241**	**172,388**
Production costs (per Mcfe):									
Lease operating expenses	$ 1.41	1.30	1.15	.91	.71	.76	1.28	1.21	1.10
Production and property taxes	.40	.29	.21	.10	.11	.05	.32	.26	.19
Transportation and processing costs	.13	.10	.09	.32	.22	.13	.18	.12	.10
Total production costs (per Mcfe)	**$ 1.94**	**1.69**	**1.45**	**1.33**	**1.04**	**.94**	**1.78**	**1.59**	**1.38**

(1) Include the effects of hedging under cash flow hedge accounting. See Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations", concerning our hedging activities and the effects of energy swaps and collars not accounted for under cash flow hedge accounting.

Marketing and Delivery Commitments

Our oil and gas production is sold to various purchasers in accordance with our credit policies and procedures. These 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, absent a broad market disruption. In 2006, sales to FB Energy Canada Corp and Tesoro Alaska Petroleum Company represented approximately 12% and 13%, respectively, of our total oil and gas revenue.

Our natural gas production is typically sold on a month-to-month basis in the spot market, priced in reference to 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. In Canada, a portion of our natural gas production is also sold 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.

Competition

Forest encounters competition in all aspects of its business, including acquisition of properties and oil and gas leases, marketing oil and gas, obtaining services and labor, and securing drilling rigs and other equipment necessary for drilling and completing wells. Our ability to increase reserves in the future will depend on our ability to generate successful prospects on our existing properties, execute on major development drilling programs, 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 both equipment, service and labor costs in the industry as well as 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 United States 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.

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, 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 depend on prescribed reference prices, well productivity, geographical location, and the type or quality of the product produced. Any royalties payable on production from privately owned lands are determined by negotiations between Forest and the landowners.

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 exploration, production and transportation operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper closure of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of capital 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.

Employees

As of December 31, 2006, we had 585 employees, including 193 who were employees of our drilling subsidiary. None of our employees is currently represented by a union for collective bargaining purposes.

Geographical Data

Forest operates in one industry segment. For information relating to our geographic operating segments, see Note 14 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. We also lease field offices and subsidiary offices throughout the United States and Canada and in Cape Town, South Africa. Upon consummation of the proposed merger with Houston Exploration, we expect to establish an office in Houston, Texas.

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 and term loan facilities, we have granted the lenders a lien on a majority of our properties. In addition, our properties may also be subject to liens incident to operating agreements, as well as other customary encumbrances, easements, and restrictions, and for current taxes not yet due. Forest's general practice is to conduct a title examination on material property acquisitions. Prior to the commencement of drilling operations, a title examination and, if necessary, curative work is performed. The methods of title examination that we have adopted are reasonable in the opinion of management and are designed to insure that production from our properties, if obtained, will be salable for the account of Forest.

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Form 10-K. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X. The entire definitions of those terms can be viewed on the SEC's website at *http://www.sec.gov/about/forms/regs-x.pdf*.

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

Bcf. Billion cubic feet of natural gas.

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

Bbtu. One billion British Thermal Units.

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

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

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

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

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

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

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

Exploratory well. A well drilled to find and produce oil or gas reserves not classified as proved, 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 or the undertaking of other work obligations.

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

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

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

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

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

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

Mcf. Thousand cubic feet of natural gas.

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

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

MMcf. Million cubic feet of natural gas.

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

NGL. Natural gas liquids.

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

NYMEX. New York Mercantile Exchange.

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

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

Proved reserves. 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.

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

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

Undeveloped Acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of 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 to receive 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 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 May 2006, 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 Principal Executive Officer and Principal 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. Generally, the words "expects," "anticipates," "targets," "goals," "projects," "intends," "plans," "believes," "seeks," "estimates," variations of such words and similar expressions identify forward-looking statements, and any statements regarding Forest's future financial condition, results of operations and business, are also 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;
- the amount, nature and timing of any synergies or other benefits expected to result from acquisitions, including the proposed merger with Houston Exploration;
- 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 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.

Factors that could cause actual results to differ materially from those contemplated by the forward-looking statements include, among others, the following factors related to the proposed merger with Houston Exploration:

- the ability to consummate the merger;
- difficulties and delays in obtaining regulatory approvals for the merger;
- difficulties and delays in achieving synergies and cost savings from the merger; and
- potential difficulties in meeting conditions set forth in the merger agreement.

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.

Risk Factors Relating to Forest

Oil and gas price declines adversely affect Forest's financial results 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 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 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 53% of our estimated proved reserves as of December 31, 2006 were natural gas reserves, our financial results in 2007 are more sensitive to movements in natural gas prices. We have announced plans to complete a merger with Houston Exploration and the vast majority of Houston Exploration's estimated proved reserves are natural gas, therefore, our financial results will be even more sensitive to natural gas price fluctuations following the proposed merger. For all of these reasons, declines in oil and gas prices 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 are favorable. We also continue to examine alternative sources of long-term capital such as 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 will 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. We expect that the terms of our proposed amended and restated credit facilities to be entered into in connection with the proposed merger with Houston Exploration will be substantially similar to Forest's existing credit facilities. See "*—Leverage materially affects 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 any 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. 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 State 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. See "*Additional Risk Factors Relating to Forest if the Merger with Houston Exploration is Consummated—Forest will be more vulnerable to a ceiling test writedown following the merger with Houston Exploration*" below.

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 our 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 and other factors may cause us to record ceiling test 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. The merger with Houston Exploration is expected to increase the risk of a ceiling test writedown. See "*Additional Risk Factors Relating to Forest if the Merger with Houston Exploration is Consummated—Forest will be more vulnerable to a ceiling test writedown following the merger with Houston Exploration*" below.

Leverage may materially affect our operations. As of December 31, 2006, the principal amount of our consolidated long-term debt was approximately $1.2 billion, including approximately $107 million outstanding under the combined U.S. and Canadian bank credit facilities among Forest and its Canadian subsidiary and the various lenders that are parties to the facilities and $375 million outstanding under term loan facilities among Forest Alaska Operating LLC and the lenders that are parties to those facilities, which are nonrecourse to Forest and its non-Alaska subsidiaries. Our long-term debt represented 46% of our total capitalization at December 31, 2006. Further, we may incur additional debt in the future, including in connection with acquisitions and refinancings. In connection with the announcement of the proposed merger with Houston Exploration, we also announced our plans to enter into an amended and restated $1.4 billion credit facility which will be used to finance the cash component of the merger consideration, which is expected to total approximately $740 million. See *"Risk Factors Relating to Forest if the Merger with Houston Exploration is Consummated"* below.

The level of our debt has several important effects on our operations, including, among others:

- a significant portion of our cash flow from operations could 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 change in the future, 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 in turn impact the costs, terms, conditions, and availability of financing;
- covenants contained in our existing and future credit and debt arrangements require us to meet financial tests that 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 is limited and any such financing may be burdened by increased costs or more restrictive covenants;
- we may be at a competitive disadvantage to similar companies that have less debt; and
- we are more vulnerable to adverse economic and industry conditions.

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, 2006, our estimated discounted asset retirement obligation liability recorded in the balance sheet was approximately $64.1 million, of which $16.9 million was for properties in the Cook Inlet of Alaska. Approximately $6.7 million of abandonment costs were settled in 2006 and $2.7 million of abandonment costs are anticipated to be settled in 2007, 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. 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 declines or 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 oil and gas drilling and production activities are subject to numerous operational and exploration risks. 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 risks 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 19% of our 2006 consolidated production costs, and 22% of our 2006 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 that have tested natural gas. While no proved reserves have been assigned to these properties as commercial sales contracts have not been established, and if we are unable to arrange for commercial use of these properties, we may not be able to recoup our investment and may 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 2006, our hedging arrangements reduced the benefits we received from increases in oil and natural gas prices by approximately $67.7 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 9 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. 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 both equipment, service and labor costs in the industry as well as 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. In addition, oil and gas producers are increasingly facing competition from providers of non-fossil energy, and government policy may favor those competitors in the future. Many of these competitors have financial and other resources substantially greater than ours. We can give no assurance that we will be able to compete effectively in the future and that our financial condition and results of operations will not suffer as a result.

Our growth may 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 from the drilling subsidiary. 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.

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.

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.

Additional Risk Factors Relating to Forest if the Merger with Houston Exploration is Consummated

The businesses of Forest and Houston Exploration, as well as other businesses that Forest may acquire after completion of the merger, may be difficult to integrate, disrupt Forest's business, dilute shareholder value or divert management attention. Risks with respect to the combination of Forest and Houston Exploration, as well as other recent and future acquisitions, include:

- difficulties in the integration of the operations and personnel of the acquired company;
- diversion of management's attention away from other business concerns; and
- the assumption of any undisclosed or other potential liabilities of the acquired company.

Forest will be more vulnerable to a ceiling test writedown following the merger with Houston Exploration. As described above in the risk factor entitled, "*Risk Factors Relating to Forest—Lower oil and gas prices and other factors may cause us to record ceiling test writedowns*," Forest uses the full cost method of accounting and is subject to quarterly ceiling tests. After completion of the merger, Forest will add to net capitalized costs the cost to acquire Houston Exploration's oil and gas properties. It will also add the estimated proved reserves associated with those properties. Forest expects that the net effect of these additions will be to reduce the difference between the ceiling limit and the net capitalized costs of its U.S. cost center. Based on oil and gas prices at December 31, 2006, on a stand-alone basis Forest had a ceiling limit in excess of the net capitalized costs in the U.S. cost center (the "Available Amount") of approximately $535 million. Based on Forest's current estimate of the cost to acquire Houston Exploration's properties and the estimated proved reserves to be acquired, Forest's Available Amount would have been approximately $100 million if the pending merger with Houston Exploration had occurred on December 31, 2006. The impact on the Available Amount indicates that Forest may be more likely to incur a writedown of its U.S. full cost pool immediately after the merger than it would have been immediately before the merger.

Forest will incur substantial transaction and merger-related costs in connection with the merger. We expect to incur a number of non-recurring transaction and merger related costs (estimated to be in excess of $50 million) associated with completing the merger with Houston Exploration, combining the operations of the two companies and achieving desired synergies. These fees and costs will be substantial. Additional unanticipated costs may be incurred in the integration of the businesses of Forest and Houston Exploration. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses will offset the incremental transaction and merger-related costs over time, this net benefit may not be achieved in the near term, or at all.

Forest will have substantial debt after the effective time of the merger, which could have a material adverse effect on its financial health and limit its future operations. Forest will have a significant amount of additional debt after the effective time of the merger. Approximately $740 million (based on the number of shares of Houston Exploration common stock outstanding on January 4, 2007) in expected cash consideration is expected to be paid with borrowings under Forest's proposed amended and restated credit facilities. Forest's substantial debt could have important consequences. In particular, it could:

- increase its vulnerability to general adverse economic and industry conditions;
- require it to dedicate a substantial portion of its cash flow from operations to payments on its indebtedness, thereby reducing the availability of its cash flow to fund working capital, capital expenditures and other general corporate purposes;
- place it at a competitive disadvantage compared to its competitors that have less debt; and
- limit, along with the financial and other restrictive covenants of its indebtedness, among other things, its ability to borrow additional funds.

See, "Risk Factors Relating to Forest—Leverage may materially affect our operations" above.

Item 1B. Unresolved Staff Comments.

None.

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.

Houston Exploration and Forest are subject to an ongoing shareholder lawsuit, which could result in an injunction preventing the consummation of the merger or significant monetary damages. Houston Exploration's directors and Forest are defendants in a shareholder lawsuit brought by the City of Monroe Employees' Retirement System (the "Plaintiff") on June 22, 2006 in State court in Houston, Texas. The Plaintiff asserts that the Houston Exploration directors breached their fiduciary duties by not pursuing a June 12, 2006 unsolicited proposal to purchase the outstanding shares of Houston Exploration common stock for $62 per share that was made by a Houston Exploration shareholder. The Plaintiff also asserts, on behalf of an uncertified class of Houston Exploration's shareholders, that the Houston Exploration directors' decision to enter into the merger agreement with Forest constituted a breach of fiduciary duties, because, the Plaintiff alleges, the merger consideration being offered by Forest is inadequate. The Plaintiff asserts that Forest aided and abetted the Houston Exploration directors' alleged breach of fiduciary duties.

At the time of the filing of this Annual Report, this lawsuit is at an early stage and subject to substantial uncertainties concerning the outcome of material factual and legal issues. Accordingly, based on the current status of the litigation, we cannot currently predict the manner and timing of the resolution of the lawsuit, the likelihood of the issuance of an injunction preventing the consummation of the merger or an estimate of a range of possible losses or any minimum loss that could result in the event of an adverse verdict in the lawsuit. Furthermore, although the combined company's insurance policies following the merger should provide coverage for the claims against Houston Exploration's directors, the policies may not be sufficient to cover all costs and liabilities incurred by those directors. The current claim in the lawsuit against Forest is not covered by insurance.

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, 2006.

Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of February 27, 2007.

Name	Age	Years with Forest	Office[(1)]
H. Craig Clark	50	6	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 employed by Apache Corporation, an oil and gas exploration and production company, from 1989 to 2001, where 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	50	19	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	56	18	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	50	4	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.
J.C. Ridens	51	3	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	45	7	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	44	8	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	43	5	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	33	2	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 16, 2007, our Common Stock was held by 640 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange composite tape, as well as adjusted prices for Forest common stock that reflect the stock dividend paid by Forest on March 2, 2006. There were no cash dividends declared on the Common Stock in 2005 or 2006. On February 27, 2007, the closing price of Forest Common Stock was $32.14.

		Common Stock		Common Stock (As Adjusted)[1]	
		High	Low	High	Low
2005	First Quarter	$43.29	28.87	29.00	19.34
	Second Quarter	44.00	34.21	29.47	22.91
	Third Quarter	54.76	40.77	36.68	27.31
	Fourth Quarter	54.25	40.26	36.34	26.97
2006	First Quarter	$52.99	32.51	37.82	30.80
	Second Quarter	39.75	28.00	39.75	28.00
	Third Quarter	35.28	29.06	35.28	29.06
	Fourth Quarter	36.17	29.13	36.17	29.13

(1) On March 2, 2006, Forest completed the Spin-off by means of a special stock dividend paid to all shareholders of Forest Common Stock. The stock dividend consisted of 0.8093 shares of a wholly owned subsidiary of Forest for each outstanding share of Forest Common Stock, which immediately thereafter became the right to receive one share of Mariner for each whole share of such subsidiary in connection with the merger of MERI and such subsidiary. Mariner's common stock commenced trading on March 3, 2006 at a price of $20.40. Based on the ratio of 0.8093 Mariner shares for each Forest share, the value of the stock dividend to Forest shareholders is deemed by Forest to be equal to $16.51, or the price of Mariner common stock on March 3, 2006 ($20.40) multiplied by 0.8093.

The prices shown in the "As Adjusted" column above for the first quarter of 2005 through the first quarter of 2006 have been adjusted to reflect the stock dividend paid on March 2, 2006. The ratio used for this historical price adjustment is 0.6698. This represents the ratio of (x) $33.49, the per share value of Forest Common Stock immediately after the stock dividend, which was the opening price for Forest shares on March 3, 2006, to (y) $50.00, which represents the sum of $33.49 plus $16.51, the value of the stock dividend described above. That is $33.49 divided by $50.00 equals 0.6698. Prices from the second quarter of 2006 onward are identical in both columns.

Dividend Restrictions

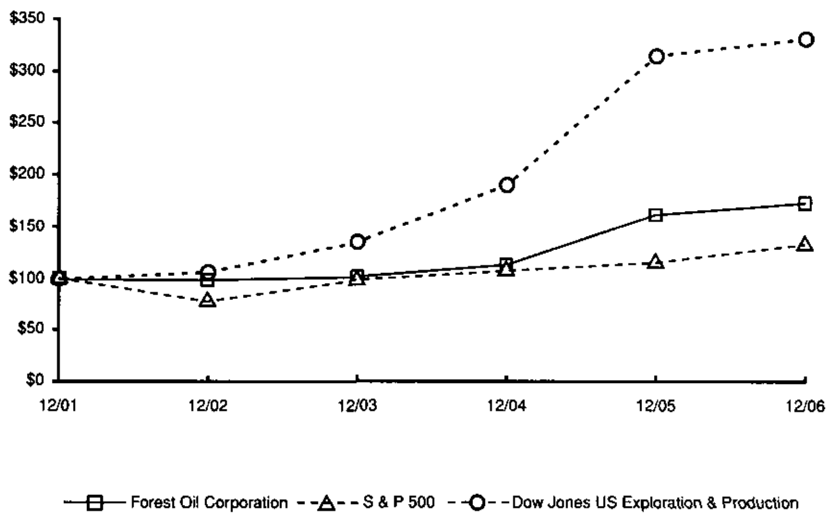
Forest's present or future ability to pay dividends is governed by (i) the provisions of the New York Business Corporation Law, (ii) Forest's restated certificate of incorporation and bylaws, (iii) Forest's 8% Senior Notes due 2008, Forest's 8% Senior Notes due 2011, and Forest's 7¾% Senior Notes due 2014, and (iv) Forest's United States and Canadian bank credit facilities dated as of September 29, 2004, as amended. The provisions in the indentures pertaining to these Senior Notes and in the bank credit facilities limit our ability to make restricted payments, which include dividend payments. Also, if the merger with Houston Exploration is completed, the indenture governing its senior subordinated notes will limit our ability to pay dividends. As noted above, on March 2, 2006 Forest distributed a special stock dividend; however, Forest has not paid cash dividends on its Common Stock during the past five years. The future payment of cash dividends, if any, on the Common Stock is within the discretion of the Board of Directors and will depend on Forest's earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that Forest will pay any cash dividends.

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 and the special stock dividend. See Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations," 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 Management and Related Stockholder Matters," below.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2001 (and the reinvestment of dividends thereafter) in each of Forest Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. We believe that the Dow Jones U.S. Exploration and Production Index is meaningful because it is an independent, objective view of the performance of other similarly-sized energy companies.



The information in this Form 10-K appearing under the heading "Stock Performance Graph" is being furnished pursuant to Item 2.01(e) of Regulation S-K and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 2.01(e) of Regulation S-K, or to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended.

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, 2006. 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. On March 2, 2006, Forest completed the Spin-off of its offshore Gulf of Mexico operations. See *"Spin-off of Offshore Gulf of Mexico Operations"* under Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations" below.

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Revenue:					
Oil and gas sales	$ 814,469	1,062,517	909,780	655,193	471,740
Marketing, processing, and other	5,523	9,528	3,118	1,985	1,128
Total revenue	819,992	1,072,045	912,898	657,178	472,868
Earnings from continuing operations	166,080	151,568	123,126	90,228	21,083
Income (loss) from discontinued operations, net of tax[1]	2,422	—	(575)	(7,731)	193
Cumulative effect of change in accounting principle, net of tax[2]	—	—	—	5,854	—
Net earnings	$ 168,502	151,568	122,551	88,351	21,276
Basic earnings per share:					
Earnings from continuing operations	$ 2.67	2.47	2.16	1.82	.45
Income (loss) from discontinued operations, net of tax	.04	—	(.01)	(.15)	—
Cumulative effect of change in accounting principle, net of tax	—	—	—	.12	—
Basic earnings per common share	$ 2.71	2.47	2.15	1.79	.45
Diluted earnings per share:					
Earnings from continuing operations	$ 2.62	2.41	2.12	1.79	.44
Income (loss) from discontinued operations, net of tax	.04	—	(.01)	(.15)	—
Cumulative effect of change in accounting principle, net of tax	—	—	—	.11	—
Diluted earnings per common share	$ 2.66	2.41	2.11	1.75	.44
Total assets	$3,189,072	3,645,546	3,122,505	2,683,548	1,924,681
Long-term debt	$1,204,709	884,807	888,819	929,971	767,219
Shareholders' equity	$1,434,006	1,684,522	1,472,147	1,185,798	921,211
OPERATING DATA					
Annual production:					
Gas (MMcf)	73,024	101,833	107,366	96,977	92,068
Liquids (MBbls)	8,026	10,568	10,837	8,701	8,657
Average sales price[3]					
Gas (per Mcf)	$ 5.58	6.36	5.34	4.53	3.13
Liquids (per Bbl)	$ 50.70	39.23	31.05	24.77	21.16
Capital expenditures, net of proceeds from asset sales[4]	$ 934,192	824,045	605,133	716,554	352,812

(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.

(3) Includes the effects of hedging under cash flow hedge accounting.

(4) Does not include estimated discounted asset retirement obligations of $2.4 million, $16.3 million, $14.1 million, and $63.7 million related to assets placed in service during the years ended December 31, 2006, 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 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. We conduct our operations in three geographical segments and five business units. The geographical segments are: the United States, Canada and International. The business units are: the Western United States ("Western"), Southern United States ("Southern"), Alaska, Canada and International. We conduct exploration and development activities in each of our geographical segments; 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, 2006, approximately 84% of our estimated proved oil and gas reserves were in the United States and approximately 16% were in Canada. Forest's total estimated proved reserves as of December 31, 2006 were 1,455 Bcfe.

Recent Developments

Pending Acquisition of Houston Exploration

On January 7, 2007, Forest announced it had entered into a definitive agreement and plan of merger pursuant to which The Houston Exploration Company ("Houston Exploration") will merge with and into Forest in a stock and cash transaction totaling approximately $1.5 billion plus the assumption of debt. Houston Exploration is an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America with operations in the following four producing areas in the United States: South Texas, East Texas, the Arkoma Basin of Arkansas, and the Uinta and DJ Basins in the Rocky Mountains. The boards of directors of Forest and Houston Exploration have each unanimously approved the transaction. The transaction is subject to regulatory approvals and other customary conditions, as well as both Forest shareholder and Houston Exploration stockholder approvals. Forest management and its board of directors will continue in their current positions with Forest following the completion of the merger. The merger is expected to close in the second quarter of 2007.

Under the terms of the merger agreement, Houston Exploration stockholders are to receive total consideration equal to 0.84 shares of Forest common stock and $26.25 in cash for each share of Houston Exploration common stock outstanding. This represents estimated merger consideration of 23.6 million shares of Forest common stock and cash of approximately $740 million, or $52.47 per share, to be received by the Houston Exploration stockholders (based on the closing price of Forest's common stock on January 5, 2007 and the number of shares of Houston Exploration common stock outstanding on January 4, 2007 and subject to increase in the event that any additional shares of Houston Exploration common stock are issued prior to the merger closing date in connection with the exercise of outstanding stock options pursuant to the terms of the merger agreement). The actual amount of total cash and stock consideration to be received by each Houston Exploration stockholder will be determined by elections, an equalization formula and a proration procedure. It is anticipated that the transaction will be tax free to Houston Exploration and the stock portion of the consideration will be received tax free by its stockholders. The cash component of the acquisition is expected to be financed under an amended and restated revolving credit facility of up to $1.4 billion for which JPMorgan Chase Bank, N.A. has provided us a commitment letter.

2006 Highlights

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 stock dividend, which consisted of a pro rata spin-off (the "Spin-off") of all outstanding shares of Forest Energy Resources, Inc. (hereinafter known as Mariner Energy Resources, Inc. or "MERI"), 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, MERI was merged with a subsidiary of Mariner Energy, Inc. ("Mariner") (the "Merger"). Mariner's common stock 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 dividend of 0.8093 shares of MERI for each outstanding share of Forest common stock. In the Merger, Forest shareholders received one share of Mariner common stock for each whole share of MERI that they held. The Spin-off was a tax-free transaction for federal income tax purposes.

Cotton Valley Acquisition

On March 31, 2006, Forest completed the acquisition of oil and gas properties located primarily in the Cotton Valley trend in East Texas. Forest paid approximately $255 million, as adjusted to reflect an economic effective date of February 1, 2006, for properties with an estimated 110 Bcfe of estimated proved reserves at the time the acquisition was announced in February 2006 and production that averaged 13 MMcfe per day in January 2006. Forest obtained approximately 26,000 net acres in the fields, of which approximately 14,000 net acres were undeveloped. This acquisition provided another core area of growth and added significant onshore activity to the Southern business unit. Forest funded this acquisition utilizing its bank credit facilities.

Formation of New Alaska Subsidiaries and Related Financing

As of October 31, 2006, Forest transferred the majority of the assets associated with its Alaska business unit to a new subsidiary, Forest Alaska Operating LLC ("Forest Alaska"), which is indirectly owned 100% by Forest through another subsidiary, Forest Alaska Holding LLC. Forest Alaska holds the oil and gas interests of Forest in the Cook Inlet region of the State of Alaska and entered into a service agreement with Forest for the operation of those assets. The activities of Forest Alaska are intended to focus on the exploitation of its assets and the proposed development of the McArthur River Field over the next several years. The new subsidiary obtained $375 million of term loan financing to fund a $350 million distribution to Forest and provide initial working capital for Forest Alaska's operations. The term loans are secured by substantially all of the subsidiary's assets and are non-recourse to Forest. Concurrent with the announcement of the pending Houston Exploration merger, we announced that we intend to sell the Alaska business unit in order to reduce indebtedness associated with the pending merger of Houston Exploration.

Operational Highlights

Highlights of Forest's 2006 operations were as follows:

- Forest's year-end estimated proved reserves were 1,455 Bcfe, nearly equal to 2005's year-end estimated proved reserves of 1,467 Bcfe, notwithstanding 121 Bcfe of production in 2006 and the 313 Bcfe of estimated proved reserves distributed to our shareholders in connection with the spin-off of our offshore Gulf of Mexico operations.
- Oil and gas production in 2006 from the Retained Properties (see definition below under "Results of Operations") increased 14% to 113 Bcfe from 99 Bcfe in 2005.
- Net income increased to $169 million, or $2.66 per diluted share, in 2006 from $152 million, or $2.41 per diluted share, in 2005.
- Forest had continuing success in 2006 with its Buffalo Wallow project, East Texas Cotton Valley project, and Foothills/Wild River projects in Canada. Total drilling well counts for 2006 were 146 net wells, with a 96% success rate.
- Forest invested a total of $316 million to acquire 138 Bcfe of estimated proved reserves.
- Effective August 1, 2006, Forest took over as operator of the Katy field. Gross field production increased 54% to 20 MMcfe per day at December 31, 2006 from 13 MMcfe per day achieved through the first six months of the year.

2007 Outlook

In 2007, we expect to continue our development and exploitation activities on our onshore North American assets for which we expect continued production growth. Our capital budget for 2007 is $480 million to $520 million, not including capital expenditures planned for the Houston Exploration assets upon the closing of the proposed merger. Most of this capital budget will be directed to our large drilling programs in Buffalo Wallow, Wild River and East Texas.

We also anticipate a continued favorable commodity price environment in 2007. In our view, the economic growth and the related increased demand for oil and gas should continue to support historically 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. Our 2007 plan anticipates cash flow from operations greater than our exploration and development spending levels, which surplus is expected to be used, in whole or in part, to pay down indebtedness and fund acquisitions.

We face numerous challenges in 2007. We will be challenged with integrating the operations of the proposed acquisition of Houston Exploration. Among other matters, we plan to realign staff and responsibilities, and continue to implement effective cost structures. In addition, we expect our debt-to-book capitalization ratio to be approximately 50% after the closing of the pending Houston Exploration acquisition, which is higher than our targeted ratio of 30% to 40%. We expect to lower the ratio by selling our Alaska business unit and certain other non-core assets. We expect to continue to pursue asset acquisition opportunities in 2007, 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 consistent with the levels experienced in 2006. Our challenge will be to economically add reserves, through drilling and acquisitions, and operate our productive assets in a cost-efficient manner that achieves attractive returns for our shareholders.

Results of Operations

As a result of the Spin-off discussed above, the revenues and expenses associated with our offshore Gulf of Mexico operations are only included in our consolidated results of operations through February 28, 2006. As a result, the operational results for 2006 presented are not comparable to results for 2005. As such, revenues and expenses in 2006 and 2005 that are directly attributable to the properties included in the Spin-off (the "Spin-off Properties") and those retained (the "Retained Properties") are discussed separately.

For the year ended December 31, 2006, Forest reported net earnings of $168.5 million or $2.71 per basic share, an 11% increase compared to net earnings of $151.6 million or $2.47 per basic share in the corresponding 2005 period. The increase in net earnings in 2006 compared to 2005 was primarily due to increases in net unrealized gains on our derivative instruments offset by decreased earnings from operations as a result of the Spin-off transaction discussed above. 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. 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, 2006, 2005, and 2004 are set forth in the table below.

	Year Ended December 31,											
	2006				2005				2004			
	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Total (MMcfe)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Total (MMcfe)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Total (MMcfe)
Production volumes:												
Retained Properties:												
United States	42,296	5,050	1,562	**81,968**	33,792	5,342	1,191	**72,990**	29,736	5,772	548	**67,656**
Canada	24,350	739	400	**31,184**	18,921	844	408	**26,433**	15,946	897	390	**23,668**
Total Retained Properties	66,646	5,789	1,962	**113,152**	52,713	6,186	1,599	**99,423**	45,682	6,669	938	**91,324**
Spin-off Properties	6,378	193	82	**8,028**	49,120	2,070	713	**65,818**	61,684	2,624	606	**81,064**
Totals	73,024	5,982	2,044	**121,180**	101,833	8,256	2,312	**165,241**	107,366	9,293	1,544	**172,388**
Revenues (In Thousands):												
Retained Properties:												
United States	$248,075	314,410	49,616	**612,101**	234,895	282,013	34,643	**551,551**	168,665	224,319	13,528	**406,512**
United States hedging effects(1)	(967)	(20,526)	—	**(21,493)**	(16,309)	(41,898)	—	**(58,207)**	(16,650)	(43,411)	—	**(60,061)**
Canada	123,408	37,605	16,559	**177,572**	126,771	35,382	14,748	**176,901**	67,398	31,839	10,953	**110,190**
Total Retained Properties	370,516	331,489	66,175	**768,180**	345,357	275,497	49,391	**670,245**	219,413	212,747	24,481	**456,641**
Spin-off Properties	53,975	11,614	3,020	**68,609**	389,562	109,213	21,732	**520,507**	388,559	105,113	16,535	**510,207**
Spin-off Properties hedging effects (1)	(16,926)	(5,394)	—	**(22,320)**	(86,983)	(41,252)	—	**(128,235)**	(34,630)	(22,438)	—	**(57,068)**
Total Spin-off Properties	37,049	6,220	3,020	**46,289**	302,579	67,961	21,732	**392,272**	353,929	82,675	16,535	**453,139**
Totals	$407,565	337,709	69,195	**814,469**	647,936	343,458	71,123	**1,062,517**	573,342	295,422	41,016	**909,780**
Average sales price:												
Retained Properties:												
United States	$ 5.87	62.26	31.76	**7.47**	6.95	52.79	29.09	**7.56**	5.67	38.86	24.69	**6.01**
United States hedging effects(1)	(.02)	(4.06)	—	**(.26)**	(.48)	(7.84)	—	**(.80)**	(.56)	(7.52)	—	**(.89)**
Canada	5.07	50.89	41.40	**5.69**	6.70	41.92	36.15	**6.69**	4.23	35.49	28.08	**4.66**
Total Retained Properties	5.56	57.26	33.73	**6.79**	6.55	44.54	30.89	**6.74**	4.80	31.90	26.10	**5.00**
Spin-off Properties	8.46	60.18	36.83	**8.55**	7.93	52.76	30.48	**7.91**	6.30	40.06	27.29	**6.29**
Spin-off Properties hedging effects(1)	(2.65)	(27.95)	—	**(2.78)**	(1.77)	(19.93)	—	**(1.95)**	(.56)	(8.55)	—	**(.70)**
Total Spin-off Properties	5.81	32.23	36.83	**5.77**	6.16	32.83	30.48	**5.96**	5.74	31.51	27.29	**5.59**
Totals	$ 5.58	56.45	33.85	**6.72**	6.36	41.60	30.76	**6.43**	5.34	31.79	26.56	**5.28**

(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.

Net oil and gas production from the Retained Properties in 2006 was 113.2 Bcfe or an average of 310.0 MMcfe per day, a 14% increase from 99.4 Bcfe or an average of 272.4 MMcfe per day in 2005. The net increase in oil and gas production was primarily attributable to increases at the Buffalo Wallow field and the recently acquired East Texas properties in the United States and the Wild River field in Canada. Oil and natural gas revenues from the Retained Properties were $768.2 million in 2006, a 15% increase as compared to $670.2 million in 2005. The increase in oil and natural gas revenues from the Retained Properties was due to the 14% increase in production and a 1% increase in the average realized sales price per Mcfe from $6.74 in 2005 to $6.79 in 2006.

Oil and gas production from the Spin-off Properties in 2006 was 8.0 Bcfe or an average of 136.1 MMcfe per day (through February 28, 2006) compared to 65.8 Bcfe or an average of 180.3 MMcfe per day in 2005. Average daily production in 2006 was lower than in 2005 due to shut-in production resulting from hurricanes Rita and Katrina in the third and fourth quarters of 2005. Oil and gas revenues from the Spin-off Properties totaled $46.3 million in 2006 resulting in an average price per Mcfe of $5.77 compared to oil and natural gas revenues from the Spin-off Properties of $392.3 million, or $5.96 per Mcfe in 2005. The decrease in total production and total oil and gas revenues was due to the fact that 2006 includes only two months of offshore production given the Spin-off on March 2, 2006.

Oil and gas sales revenues from all properties increased $152.7 million in 2005 compared to 2004 as a 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 average realized sales prices for the periods presented include losses that we recognized on our derivative instruments designated as cash flow hedges. For the years ended December 31, 2006, 2005 and 2004, Forest recognized hedging losses of $43.8 million, $186.4 million, and $117.1 million, respectively. The recognized losses in 2006 include $15.2 million in hedge losses settled in the fourth quarter of 2005 but recognized in the first quarter of 2006 to correspond with the timing of the production that was deferred by hurricanes Katrina and Rita. See *Realized and Unrealized Gains and Losses on Derivative Instruments* below for information on gains and losses recognized on derivative instruments not designated as cash flow hedges during the last three years.

Oil and Gas Production Expense

The table below sets forth the detail of oil and gas production expense for the years ended December 31, 2006, 2005, and 2004:

	Year Ended December 31,								
	2006			2005			2004		
	Retained Properties	Spin-off Properties	Total	Retained Properties	Spin-off Properties	Total	Retained Properties	Spin-off Properties	Total
	(In Thousands, Except per Mcfe Data)								
Lease operating expenses ("LOE"):									
Direct operating expense and overhead	$123,191	9,377	**132,568**	103,742	62,377	**166,119**	99,597	66,386	**165,983**
Workover expense	13,369	8,761	**22,130**	17,096	12,915	**30,011**	9,485	11,573	**21,058**
Hurricane repairs	18	158	**176**	399	3,232	**3,631**	—	2,120	**2,120**
Total LOE	$136,578	18,296	**154,874**	121,237	78,524	**199,761**	109,082	80,079	**189,161**
LOE per Mcfe	$ 1.21	2.28	**1.28**	1.22	1.19	**1.21**	1.19	.99	**1.10**
Production and property taxes	$ 38,890	151	**39,041**	40,400	2,215	**42,615**	30,693	1,548	**32,241**
Production and property taxes per Mcfe	$ .34	.02	**.32**	.41	.03	**.26**	.34	.02	**.19**
Transportation and processing costs	$ 21,532	344	**21,876**	16,116	3,383	**19,499**	14,617	2,175	**16,792**
Transportation and processing costs per Mcfe	$ .19	.04	**.18**	.16	.05	**.12**	.16	.03	**.10**

Lease Operating Expenses

Lease operating expenses for the Retained Properties increased 13%, or $15.3 million, to $136.6 million in 2006 from $121.2 million in 2005. However, on a per-Mcfe basis, LOE from the Retained Properties decreased slightly to $1.21 per Mcfe in 2006 from $1.22 per Mcfe in 2005. Lease operating expenses for the Spin-off Properties were $18.3 million in 2006 compared to $78.5 million in 2005. On a per-Mcfe basis, LOE from the Spin-off properties increased $1.09 per Mcfe in 2006 to $2.28 per Mcfe from $1.19 per Mcfe in 2005 primarily due to a relative increase in workover expenses.

Lease operating expenses from all properties increased $10.6 million to $199.8 in 2005 from $189.2 in 2004. On a per-unit basis, lease operating expenses increased 10% to $1.21 per Mcfe in 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. 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.

Production and Property Taxes

Production and property taxes on the Retained Properties decreased by 4% or $1.5 million in 2006 as compared to the prior year. The decrease from the prior year is primarily attributable to severance tax incentives provided in Texas, partially offset by higher realized oil and gas revenues and higher assessed property valuations. Production and property taxes incurred on the Spin-off Properties were $.2 million during 2006 compared to $2.2 million during 2005. The decrease in the Spin-off Properties' production and property taxes was due to the fact that 2006 includes only two months of activity. The increase in production and property taxes of $10.4 million from 2004 to 2005 on all properties was 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 4.5%, 3.4%, and 3.1% for the years ended December 31, 2006, 2005, and 2004, respectively. The increase 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 and Processing Costs

Transportation and processing costs for the Retained Properties were $21.5 million or $.19 per Mcfe in 2006 compared to $16.1 million or $.16 per Mcfe in 2005. The increase of $5.4 million or $.03 per Mcfe was primarily due to higher transportation and processing costs in Canada and Alaska. Transportation and processing costs for the Spin-off Properties on a per-Mcfe basis were $.04 for 2006 compared to $.05 during the prior year. Transportation and processing costs for all properties were $19.5 million or $.12 per Mcfe in 2005 and $16.8 million or $.10 per Mcfe in 2004. The increase of $2.7 million or $.02 per Mcfe was due to increases in transportation and processing rates and increases in fuel prices.

General and Administrative Expense

The following table summarizes the components of general and administrative expense and stock-based compensation expense incurred during the periods:

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands, Except Per Mcfe Data)		
Total general and administrative costs before stock-based compensation	$ 58,108	68,934	55,911
General and administrative costs capitalized	(23,730)	(25,994)	(23,888)
General and administrative expense before stock-based compensation	$ 34,378	42,940	32,023
General and administrative expense per Mcfe	$ 0.28	0.26	0.19
Total stock-based compensation costs	$ 22,048	1,275	203
Stock-based compensation costs capitalized	(8,118)	(512)	(81)
Stock-based compensation expense	$ 13,930	763	122
Stock-based compensation expense per Mcfe	$ 0.11	—	—
Total general administrative expense including stock-based compensation	$ 48,308	43,703	32,145

General and Administrative Expenses

The decrease in general and administrative expense before stock-based compensation to $34.4 million in 2006 from $42.9 million in 2005 was primarily related to salary and benefit savings related to a reduction in the number of employees subsequent to the Spin-off as well as a $1.9 million reduction in our post-retiree medical benefit liability caused by a curtailment in the post-retiree medical benefit plan also as a result of the Spin-off. The increase of $10.9 million in general and administrative costs in 2005 as compared to 2004 was primarily related to an increase in salaries and related employee benefit costs caused by our hiring additional employees in conjunction with acquisitions completed in 2004 and early 2005 and general increases in salaries due to the competitive market for experienced oil and gas professionals. The percentage of general and administrative costs capitalized remained relatively constant between the three years, ranging between 38% and 43%.

Stock-Based Compensation Expense

The significant increase in stock-based compensation in 2006 is due to the implementation of Statement of Financial Accounting Standards ("SFAS") No. 123 (Revised), *"Share-Based Payment"* ("SFAS 123(R)"). Under this method of accounting, compensation cost is recorded for all unvested stock options, restricted stock, and phantom stock units beginning in the period of adoption and prior financial statements are not restated. Under the fair value recognition provisions of SFAS 123(R), stock-based compensation is measured at the grant date based on the value of the awards and is recognized over the requisite service period (usually the vesting period). Prior to January 1, 2006, we accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, *"Accounting for Stock Issued to Employees"*, and related interpretations. Under APB Opinion No. 25, no compensation expense was recognized for stock options issued to employees because the grant price equaled or was above the market price on the date of the option grant.

In accordance with the provisions of SFAS 123(R), stock-based compensation cost in the amount of $22.0 million was recorded during the year ended December 31, 2006 of which approximately $9.7 million is attributed to a partial settlement of Forest's restricted stock awards and phantom stock unit awards in connection with the Spin-off. Of the $22.0 million total, $13.9 million was recorded as compensation expense and $8.1 million, or 37%, was capitalized to oil and gas properties in accordance with the full cost method of accounting.

Depreciation and Depletion; Undeveloped Properties

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands, Except Per Mcfe Amounts)		
Depreciation and depletion expense	$266,881	368,679	354,092
Depreciation and depletion expense per Mcfe	$ 2.20	2.23	2.05

Depreciation, depletion, and amortization expense ("DD&A") in 2006 was $266.9 million compared to $368.7 million in 2005. On an equivalent Mcf basis, DD&A expense remained consistent at $2.20 per Mcfe in 2006 compared to $2.23 per Mcfe in 2005. The more significant change between 2005 and 2004 of $.18 per Mcfe was due primarily to higher anticipated drilling and completion costs on future development activities in 2005 as well as the effect of property divestitures in Canada in late 2004.

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

December 31,	United States	Canada	International	Total
		(In Thousands)		
2006	$149,687	53,034	58,538	261,259
2005	174,249	44,798	56,637	275,684
2004	106,908	46,730	55,966	209,604

The decrease in the total undeveloped properties of $14.4 million in 2006 from 2005 was due primarily to the Spin-off transaction noted above offset by property acquisitions completed during 2006, including the Cotton Valley assets in East Texas. The increase in the total undeveloped properties in 2005 from 2004 was due primarily to the additional undeveloped properties acquired in 2005 in conjunction with the Buffalo Wallow acquisition. See Note 2 to the Consolidated Financial Statements for additional information on the Cotton Valley and Buffalo Wallow acquisitions.

Accretion of Asset Retirement Obligations

Accretion expense of approximately $7.1 million in 2006, and $17.3 million in both 2005 and 2004 was related to the accretion of Forest's asset retirement obligations pursuant to 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 and a corresponding increase in the carrying amount of the related long-lived asset. The significant decrease in 2006 is attributable to the large reduction in future abandonment liabilities associated with the Spin-off on March 2, 2006, discussed above.

International Impairments

Forest recorded impairments related to its international properties of $3.7 million in 2006 with $2.1 recorded during the second quarter of 2006 related to a dry hole drilled in Gabon and $1.6 million recorded during the fourth quarter of 2006 related to expired concessions in Italy. 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 rationalized our international assets to concentrate on fewer areas. In 2004, Forest recorded impairments of international oil and gas properties of $4.1 million related to evaluations of projects in Albania, Germany, and Italy.

Interest Expense

Interest expense of $71.8 million in 2006 was 17% greater than in 2005, primarily due to higher average interest rates and higher average debt balances. Interest expense of $61.4 million in 2005 was 6% greater than $57.8 million in 2004, due primarily to higher average debt balances.

Realized and Unrealized Gains and 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 where hedge accounting was discontinued during their term. When the criteria for cash flow hedge accounting are not met or when cash flow hedge accounting is not elected, realized gains and losses (i.e., cash settlements) are recorded under other income and 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.

Because a significant portion of our derivatives no longer qualified for hedge accounting and to increase clarity in our financial statements, Forest elected to discontinue hedge accounting for all of its remaining commodity derivatives beginning in March 2006. Subsequent to March 2006, Forest has recognized mark-to-market gains and losses in earnings, rather than deferring such amounts in accumulated other comprehensive income included in shareholders' equity. This change in reporting has had no impact on Forest's reported cash flows, although results of operations have been affected by mark-to-market gains and losses, which fluctuate with volatile oil and gas prices.

The table below sets forth realized and unrealized gains and losses principally related to our derivatives that did not qualify for hedge accounting or where hedge accounting was not elected for the periods indicated, which were recorded under other income and expense:

	Year Ended December 31,		
	2006	2005	2004
		(In Thousands)	
Realized (losses) gains	$(23,864)	(35,390)	336
Unrealized gains (losses)	83,629	(21,373)	(1,088)
Total	$ 59,765	(56,763)	(752)

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.

	Year Ended December 31,		
	2006	2005	2004
		(In Thousands)	
Realized losses included in oil and gas revenue	$(43,813)	(186,442)	(117,129)

Other (Income) Expense, Net

The components of other (income) expense, net for the years ended December 31, 2006, 2005, and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Realized foreign currency exchange gain	$ (315)	—	(4,728)
Franchise taxes	1,410	1,963	1,219
Share of (income) loss of equity method investee	(2,334)	562	(1,726)
Other, net	1,135	3,722	3,056
Total other (income) expense, net	$ (104)	6,247	(2,179)

The foreign currency exchange gains in 2006 and in 2004 are related to the repayment of Canadian intercompany debt and intercompany advances 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.

Income Tax Expense

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

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands, Except Percentages)		
Income tax expense	$90,903	93,358	78,744
Effective tax rate	35%	38%	39%

The decrease in our effective tax rate in 2006 to 35% from 38% in 2005, was due to a reduction in income taxes of approximately $18.0 million related to statutory rate reductions enacted in Canada and changes in the Texas income tax law, net of tax increases of $7.2 million related to the effects of the Spin-off of our offshore Gulf of Mexico operations (which includes the tax effects of non-deductible Spin-off costs and an increase in Forest's combined state income tax rates). See Note 5 to the Consolidated Financial Statements for a reconciliation of our income taxes at the statutory rate to income taxes at our effective rate for each period presented.

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 three years if Cinergy meets certain earnings goals with respect to the acquired business. During the year ended December 31, 2006, Forest recognized an additional $3.6 million contingent payment ($2.4 million net of tax) due under the agreement, which has been reflected as income from discontinued operations in the Consolidated Statements of Operations. During 2005, Forest did not record a gain or loss from the sale of discontinued operations. In 2004, Forest recorded a $.6 million loss on discontinued operations, net of tax which included marketing income, general and administrative expenses, deferred income tax expense and other income and expense items. The subsidiary's results of operations have been reported as discontinued operations in the Consolidated Statements of Operations for all years presented.

Liquidity and Capital Resources

In 2007, as in 2006, 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 2007 would adversely affect the amount of cash flow generated from operations, we utilize a hedging program to partially mitigate that risk. As of February 27, 2007, Forest has hedged approximately 55 Bcfe of its 2007 production. This level of hedging provides some certainty of the cash flow we will receive for a portion of our expected 2007 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 2007 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 January 31, 2007, we had approximately $107.2 million of outstanding borrowings and letters of credit under the bank credit facilities, and an unused borrowing base of $492.8 million. We intend to amend and restate these credit facilities in connection with our proposed merger with Houston Exploration as described below under "*Bank Credit Facilities*".

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."

In conjunction with the announcement of the pending acquisition of Houston Exploration, we also announced our plans to sell our Alaska business unit and certain other non-core assets, which should provide another source of liquidity in 2007.

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

Forest 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 Bank 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 is 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, availability under the credit facilities may, at Forest's election, be governed by certain financial covenants. Alternatively, if Forest's senior unsecured long-term debt 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 September 29, 2006, the syndicate of banks approved a Global Borrowing Base of $900 million; however, Forest did not elect to change the Global Borrowing Base allocation and the U.S. allocated borrowing base was kept at $500 million and the Canadian allocated borrowing base was kept at $100 million.

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. 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 our consolidated proved oil and gas properties, measured by value. 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.

At December 31, 2006, there were outstanding borrowings of $23.0 million under the U.S. credit facility at a weighted average interest rate of 8.5%, and there were outstanding borrowings of $84.1 million under the Canadian credit facility at a weighted average interest rate of 5.9%. We also had used the credit facilities for approximately $3.5 million in letters of credit, leaving an unused borrowing amount under the Global Borrowing Base of approximately $489.4 million at December 31, 2006. At January 31, 2007, there were outstanding borrowings of $21.0 million under the U.S. credit facility at a weighted average interest rate of 6.9%, and there were outstanding borrowings of $83.3 million under the Canadian credit facility at a weighted average interest rate of 5.9%. We also had used the credit facilities for approximately $2.9 million in letters of credit, leaving an unused borrowing amount under the Global Borrowing Base of approximately $492.8 million.

On January 5, 2007, Forest, J.P. Morgan Securities Inc. and JPMorgan Chase Bank, N.A. entered into a commitment letter and fee letter with respect to the financing of the merger with Houston Exploration and the related transactions and the refinancing of certain of Forest's existing debt. The commitment letter, which is subject to customary conditions, provides for a commitment of an aggregate of up to $1.4 billion in financing under a five-year amended and restated revolving credit facility. Initially, we anticipate the commitments for the amended and restated U.S. and Canadian credit facilities will consist of a U.S. facility of up to $1.25 billion and a Canadian facility of up to $150 million. We expect the terms of the amended and restated credit facilities to be substantially similar to those of the existing credit facilities. We expect to finance the cash portion of the merger consideration, which is expected to be approximately $740 million in cash (based on the outstanding shares of Houston Exploration common stock on January 4, 2007 and subject to increase), through borrowings under these amended and restated credit facilities. Forest also expects to use these credit facilities to pay for related merger costs and expenses and for general corporate purposes following the merger. The commitment letter expires April 30, 2007 and is subject to customary closing conditions.

Term Loan Financing Agreement

On December 8, 2006, Forest, through its wholly-owned subsidiaries Forest Alaska and Forest Alaska Holding LLC ("Forest Holding"), issued, on a non-recourse basis to Forest, term loan financing facilities in the aggregate principal amount of $375 million. The issuance was comprised of two term loan facilities, including a $250 million first lien credit agreement and a $125 million second lien credit agreement (together the "Credit Agreements"). The loan proceeds were used to fund a $350 million distribution to Forest, which Forest used to pay down its U.S. credit facility, and to provide Forest Alaska working capital for its operations and pay transaction fees and expenses. Interest on the loans are based on an adjusted LIBO rate ("LIBOR") (LIBOR plus 3.50% under the first lien credit agreement and LIBOR plus 6.50% under the second lien credit agreement) or on a rate based on the federal funds rate (federal funds rate plus 3.0% under the first lien credit agreement and federal funds rate plus 6.0% under the second lien credit agreement), at the election of Forest Alaska. The loans under the first lien agreement will become due on December 8, 2010 and the loans under the second lien agreement will become due on December 8, 2011. The term loans are secured by substantially all of the subsidiary's assets.

Partial repayments on the loans outstanding under the first lien agreement are due at the end of each calendar quarter, while the loans under the second lien agreement are scheduled for repayment on the maturity date. In addition, Forest Alaska is obligated to make mandatory prepayments annually using its excess cash flow and the proceeds associated with certain equity issuances, asset sales, and incurrence of additional indebtedness. Under certain circumstances involving a change in control involving Forest Holding or Forest Alaska, the credit agreements also require Forest Alaska to offer to repurchase outstanding loans and purchase loans put to it by the lenders and, depending on the date of any such repurchase, the repurchase price may include a premium. Upon an event of default, a majority of the lenders under each of the Credit Agreements may request the agent to declare the loans immediately payable. Under certain circumstances involving insolvency, the loans will automatically become immediately due and payable.

The Credit Agreements include terms and covenants that place limitations on certain types of activities that may be conducted by Forest Alaska and Forest Holding. The terms include restrictions or requirements with respect to additional debt, liens, investments, hedging activities, acquisitions, dividends, mergers, sales of assets, transactions with affiliates, and capital expenditures. In addition, the Credit Agreements include financial covenants addressing limitations on present value to total debt and first lien debt, interest coverage and leverage ratios.

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. If we consummate the merger with Houston Exploration as planned, we expect the terms of the amended and restated credit facilities to be substantially similar to those of the existing credit facilities.

Historical Cash Flow

Net cash provided by operating activities, net cash used by investing activities, and net cash provided (used) by financing activities for the years ended December 31, 2006, 2005, and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
		(In Thousands)	
Net cash provided by operating activities	$ 422,478	628,565	568,013
Net cash used by investing activities	(909,891)	(671,230)	(455,901)
Net cash provided (used) by financing activities	513,832	(4,596)	(68,269)

The decrease in net cash provided by operating activities in 2006 compared to 2005 of approximately $206.1 million was due primarily to the spin-off of our Gulf of Mexico operations on March 2, 2006. 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 2006 of $238.7 million was due primarily to an increase in cash used for the acquisition, exploration, and development of oil and gas properties of $214.5 million. 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 acquisition, exploration, and development of oil and gas properties of $139.0 million and a decrease in proceeds from the sale of assets of $73.9 million. The major components of cash used by investing activities for the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
		(In Thousands)	
Acquisitions	$(292,807)	(204,450)	(249,708)
Exploration and development costs	(601,641)	(475,524)	(291,292)
Other fixed assets	(21,950)	(10,743)	(2,829)
Proceeds from sales of assets	6,507	24,046	97,933
Other, net	—	(4,559)	(10,005)
Net cash used by investing activities	$(909,891)	(671,230)	(455,901)

Net cash provided by financing activities in 2006 of $513.8 million primarily included net bank borrowings on our credit facilities of $130.2 million and the issuance of term loans of $375.0 million as discussed above. 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. Net cash used by financing activities of $68.3 million in 2004 included the issuance of 5.0 million shares of common stock at a price of $24.40 per share for net proceeds of $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 Oil Company ("Wiser") acquisition. 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. In July 2004, we redeemed, at 101.583% of par value, $125 million in principal amount of 9 1/2% Senior Subordinated Notes due 2007 that were issued by Wiser. The note redemption was funded using borrowings under our U.S. credit facility.

Capital Expenditures

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

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Property acquisitions:[1]			
Proved properties	$261,525	238,942	367,974
Undeveloped properties	53,788	73,868	57,452
	315,313	312,810	425,426
Exploration:			
Direct costs	249,838	245,523	79,676
Overhead capitalized	12,121	12,811	11,917
	261,959	258,334	91,593
Development:			
Direct costs	343,885	252,509	171,166
Overhead capitalized	19,727	13,695	12,052
	363,612	266,204	183,218
Total capital expenditures[1][2][3]	$940,884	837,348	700,237

(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 and $46.6 million in 2004 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 2006, 2005, and 2004.

(2) Does not include estimated discounted asset retirement obligations of $2.4 million, $16.3 million, and $14.1 million related to assets placed in service during the years ended December 31, 2006, 2005, and 2004.

(3) Includes $37.2 million of capital expenditures related to offshore Gulf of Mexico operations from January 1, 2006 through the date of the Spin-off on March 2, 2006. Capital expenditures related to offshore Gulf of Mexico operations for 2006 consist of $.7 million for property acquisitions, $24.0 million for exploration, and $12.5 million for development.

Forest's anticipated expenditures for exploration and development in 2007 are estimated to range from $480 million to $520 million. Some of the factors impacting the level of capital expenditures in 2007 include crude oil and natural gas prices, the volatility in these prices, the cost and availability of the oil field services, and weather disruptions. These expenditures will also increase if the proposed merger with Houston Exploration is consummated.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2006:

	2007	2008	2009	2010	2011	After 2011	Total
				(In Thousands)			
Bank debt[1]	$ 6,927	6,927	112,289	—	—	—	126,143
Term loans[2]	39,438	39,216	38,995	278,774	139,183	—	535,606
Senior notes[3]	55,625	309,142	34,425	34,425	318,475	177,125	929,217
Operating leases[4]	3,611	3,329	3,278	3,132	3,090	12,375	28,815
Unconditional purchase obligations[5]	46,109	19,517	10,258	5,241	4,599	—	85,724
Other liabilities[6]	6,525	6,482	5,928	6,053	6,795	69,907	101,690
Derivative liabilities[7]	1,294	714	97	—	—	—	2,105
Approved capital projects[8]	50,687	—	—	—	—	—	50,687
Total contractual obligations	$210,216	385,327	205,270	327,625	472,142	259,407	1,859,987

(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, 2006.

(2) Term loans consists of the principal obligations on our term loans and anticipated interest payments due on each using the interest rates in effect at December 31, 2006.

(3) Senior notes consist of the principal obligations on our senior notes and anticipated interest payments due on each.

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

(5) Consists primarily of firm commitments for drilling, gathering, processing, and pipeline capacity.

(6) 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, Judgments, and Assumptions" below for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

(7) Derivative liabilities represent the fair value of liabilities for oil and gas commodity derivatives as of December 31, 2006. 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.

(8) 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, 2006. 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 $22.4 million of capital expenditures over the next three 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 $1.3 million as of December 31, 2006.

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, 2006, 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 27, 2007, 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 $19.0 million. See Part I, Item 1—"Business—Regulation" for further information.

Critical Accounting Policies, Estimates, Judgments, and Assumptions

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 included in Note 15 to the Consolidated Financial Statements.

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

Accounting for Oil and Gas Derivatives Instruments

The Company follows the provisions of SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities"* ("SFAS 133"). SFAS 133 requires the accounting recognition of all derivative instruments as either assets or liabilities at fair value. Under the provisions of SFAS 133, the Company may or may not elect to designate a derivative instrument as a hedge against changes in the fair value of an asset or a liability (a "fair value hedge") or against exposure to variability in expected future cash flows (a "cash flow hedge"). The accounting treatment for the changes in fair value of a derivative instrument 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 is designated as a hedge as noted above. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the statement of operations due to the fact that changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings as other income or expense.

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 some of its natural gas and oil hedges during the third and fourth quarters of 2005. Additionally, as a result of the Spin-off on March 2, 2006, additional commodity swaps and collars formerly designated as cash flow hedges of offshore Gulf of Mexico production also no longer qualified for hedge accounting. Because a significant portion of the

Company's derivatives no longer qualified for hedge accounting and to increase clarity in its financial statements, the Company elected to discontinue hedge accounting prospectively for all of its remaining commodity derivatives beginning in March 2006. Accordingly, after March 2006, all changes in the fair values of our derivative instruments have been and will continue to be recognized as other income or expense.

The estimated fair values of our 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.

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 in the forward oil and natural gas prices used to calculate the fair value of the derivative instruments at December 31, 2006 of $1.00 per barrel and $.10 per MMbtu, respectively, would change the fair values of our derivative instruments at December 31, 2006 by approximately $11.0 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, 2006 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, income tax assets and liabilities are generally determined based on differences between the financial statement carrying values of book assets and liabilities and their respective income tax bases (temporary differences). 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 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 book value of income tax assets is limited to the amount of the tax benefit that is more likely than not to be realized in the future.

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 future taxable income during the periods in which related 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 will reverse, management believes it is more likely than not that we will realize the benefits of these deferred tax assets, net of the existing valuation allowances at December 31, 2006. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during relevant periods are reduced.

Asset Retirement Obligations

Forest has obligations to remove tangible equipment and restore locations at the end of the oil and gas production operations. Forest's largest concentration of removal and restoration obligations is 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 No. 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.

Full Cost Method of Accounting

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.

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. Unproved properties are assessed periodically to ascertain whether impairment has occurred. An impairment of unproved property costs may be indicated through evaluation of drilling results, relinquishment of drilling rights or other information.

Under the alternative "successful efforts method" of accounting, surrendered, abandoned, and impaired leases, delay lease rentals, exploratory 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 June 2006, the Financial Accounting Standards Board issued Interpretation No. 48, *"Accounting for Uncertainty in Income Taxes," an interpretation of FAS 109, "Accounting for Income Taxes"* ("FIN 48"), to create a single model to address accounting for uncertainty in income tax positions. FIN 48 clarifies the accounting for income taxes, by prescribing a minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. Forest will adopt FIN 48 as of January 1, 2007, as required. The cumulative effect of adopting FIN 48 will be recorded in retained earnings and other accounts as applicable. The Company has not determined the effect, if any, the adoption of FIN 48 will have on the Company's financial position or results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, "*Fair Value Measurements*" ("SFAS No. 157"). This statement clarifies the definition of fair value, establishes a framework for measuring fair value, and expands the disclosures on fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We have not determined the effect, if any, the adoption of this statement will have on our financial position or results of operations.

In February 2007, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities*" ("SFAS 159"). This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this Statement permits all entities to choose to measure eligible items at fair value at specified election dates. SFAS 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. We have not determined the effect, if any, the adoption of this statement will have on our financial position or results of operations.

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.

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, 2006, 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[1]	Weighted Average Hedged Price per Bbl	Fair Value (In Thousands)
Fiscal 2007	20.0	$8.10	$8,122	7,000	$70.03	$12,252
Fiscal 2008	—	—	—	6,500	69.72	4,915
Fiscal 2009	—	—	—	5,500	69.76	4,858
Fiscal 2010	—	—	—	2,000	73.15	4,434

(1) Subsequent to December 31, 2006, Forest unwound two oil swap agreements covering 1,000 Bbl per day in 2009 and 500 Bbl per day in 2010 for total proceeds of $6.9 million.

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)
Fiscal 2007	35.0	$8.76/11.70	$26,299	4,000	$65.81/87.18	$6,531

Basis Swaps

Forest also uses basis swaps in connection with natural gas swaps in order to fix the price differential between the NYMEX Henry Hub price and the index price at which the physical gas is sold. At December 31, 2006, there were basis swaps in place covering 35.0 Bbtu per day in 2007 with a fair market value of $(1.3) million.

The fair value of our hedges based on the futures prices quoted on December 31, 2006 was a net asset of approximately $66.1 million.

The following table reconciles the changes that occurred in the fair values of our open derivative contracts during 2006, beginning with the fair value of our commodity contracts on December 31, 2005, plus the increase in fair value during the period and the fair value of commodity contracts included in the Spin-off, plus the contract losses settled and recognized during the period.

	Fair Value of Derivative Contracts (In Thousands)
As of December 31, 2005	$(150,737)
Net increase in fair value	132,092
Fair value of derivatives transferred in Spin-off	17,087
Net contract losses recognized	67,677
As of December 31, 2006	$ 66,119

In January and February 2007, we entered into four additional swap agreements and one additional collar agreement to hedge a portion of expected future production attributable to the pending acquisition of Houston Exploration as summarized in the table below.

	Natural Gas (NYMEX HH)			
	Swaps		Collars	
	Bbtu per Day	Weighted Average Hedged Price per MMBtu	Bbtu per Day	Weighted Average Hedged Floor and Ceiling Price per MMBtu
April 2007 – December 2007	40.0	$7.77	—	—
Fiscal 2008	—	—	10.0	$7.75/9.57

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 7% of Forest's total average daily production in 2006. Canadian Forest supplied 55% of the Canadian Netback Pool sales quantity in 2006, and it is estimated that Canadian Forest will supply 79% of the Canadian Netback Pool quantity in the 2007 contract year. We expect that Canadian Forest's pro rata obligations as a gas producer will increase in 2008 and future years. In 2006, the weighted average price paid under the resale contracts was approximately 55% of market value based on the average closing AECO prices during 2006. 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.

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, 2006:

	2007	2008	2009	2010	2011	2014	Total	Fair Value
			(Dollar Amounts in Thousands)					
Bank credit facilities:								
Variable rate	$ —	—	107,094	—	—	—	107,094	107,094
Average interest rate[1]	—	—	6.47%	—	—	—	6.47%	
Term loans:								
Variable rate	$2,500	2,500	2,500	242,500	125,000	—	375,000	381,250
Average interest rate[1]	8.85%	8.85%	8.85%	8.85%	11.85%	—	9.85%	
Total variable rate debt:								
Variable rate	$2,500	2,500	109,594	242,500	125,000	—	482,094	488,344
Average interest rate[1]	8.85%	8.85%	6.52%	8.85%	11.85%	—	9.10%	
Long-term debt:								
Fixed rate	$ —	265,000	—	—	285,000	150,000	700,000	720,319
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, 2006.

(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 of Forest Oil Corporation

We have audited the accompanying consolidated balance sheet of Forest Oil Corporation and subsidiaries as of December 31, 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for the year ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Forest Oil Corporation and subsidiaries at December 31, 2006, and the consolidated results of their operations and their cash flows for the year ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 1 and 7 to the consolidated financial statements, Forest Oil Corporation changed its method of accounting for Share-Based Payments in accordance with Statement of Financial Accounting Standards No. 123 (revised 2004) on January 1, 2006.

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, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2007 an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
February 27, 2007

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Forest Oil Corporation:

We have audited the accompanying consolidated balance sheet of Forest Oil Corporation and subsidiaries as of December 31, 2005 and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the two-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 the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

KPMG LLP

Denver, Colorado
March 13, 2006

FOREST OIL CORPORATION
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Data)

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 33,164	7,231
Accounts receivable	125,446	178,124
Derivative instruments	53,205	941
Deferred tax asset	—	77,346
Other current assets	49,185	52,283
Total current assets	261,000	315,925
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of $2,265,018 and $3,059,031	2,486,153	2,898,774
Unproved	261,259	275,684
Net oil and gas properties	2,747,412	3,174,458
Other property and equipment, net of accumulated depreciation and amortization of $32,504 and $32,527	42,514	25,560
Net property and equipment	2,789,926	3,200,018
Derivative instruments	15,019	—
Goodwill	86,246	87,072
Other assets	36,881	42,531
	$ 3,189,072	3,645,546
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 224,933	312,076
Accrued interest	6,235	4,260
Derivative instruments	1,294	151,678
Current portion of long-term debt	2,500	—
Asset retirement obligations	2,694	33,329
Deferred income taxes	14,907	—
Other current liabilities	11,378	21,573
Total current liabilities	263,941	522,916
Long-term debt	1,204,709	884,807
Asset retirement obligations	61,408	178,225
Derivative instruments	811	—
Deferred income taxes	191,957	329,385
Other liabilities	32,240	45,691
Total liabilities	1,755,066	1,961,024
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Preferred stock, none issued and outstanding	—	—
Common stock, 62,998,155 and 64,548,229 shares issued and outstanding	6,300	6,455
Capital surplus	1,215,660	1,529,102
Retained earnings	137,796	217,293
Accumulated other comprehensive income (loss)	74,250	(18,220)
Treasury stock, at cost, 1,861,143 shares held in 2005	—	(50,108)
Total shareholders' equity	1,434,006	1,684,522
	$ 3,189,072	3,645,546

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2006	2005	2004
	(In Thousands, Except Per Share Amounts)		
Revenue:			
Oil and gas sales:			
Natural gas	$407,565	647,936	573,342
Oil, condensate, and natural gas liquids	406,904	414,581	336,438
Total oil and gas sales	814,469	1,062,517	909,780
Marketing, processing, and other	5,523	9,528	3,118
Total revenue	819,992	1,072,045	912,898
Operating expenses:			
Lease operating expenses	154,874	199,761	189,161
Production and property taxes	39,041	42,615	32,241
Transportation and processing costs	21,876	19,499	16,792
General and administrative (including stock-based compensation)	48,308	43,703	32,145
Depreciation and depletion	266,881	368,679	354,092
Accretion of asset retirement obligations	7,096	17,317	17,251
Impairment and other	3,668	11,132	12,929
Spin-off and merger costs	5,416	—	—
Total operating expenses	547,160	702,706	654,611
Earnings from operations	272,832	369,339	258,287
Other income and expense:			
Interest expense	71,787	61,403	57,844
Unrealized (gains) losses on derivative instruments, net	(83,629)	21,373	1,088
Realized losses (gains) on derivative instruments, net	23,864	35,390	(336)
Unrealized foreign currency exchange loss	3,931	—	—
Other (income) expense, net	(104)	6,247	(2,179)
Total other income and expense	15,849	124,413	56,417
Earnings before income taxes and discontinued operations	256,983	244,926	201,870
Income tax expense:			
Current	2,126	3,498	2,960
Deferred	88,777	89,860	75,784
Total income tax expense	90,903	93,358	78,744
Earnings from continuing operations	166,080	151,568	123,126
Income (loss) from discontinued operations, net of tax	2,422	—	(575)
Net earnings	$168,502	151,568	122,551
Basic earnings per common share:			
Earnings from continuing operations	$ 2.67	2.47	2.16
Income (loss) from discontinued operations, net of tax	.04	—	(.01)
Basic earnings per common share	$ 2.71	2.47	2.15
Diluted earnings per common share:			
Earnings from continuing operations	$ 2.62	2.41	2.12
Income (loss) from discontinued operations, net of tax	.04	—	(.01)
Diluted earnings per common share	$ 2.66	2.41	2.11

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Capital Surplus	(Accumulated Deficit) Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Treasury Stock	Total Shareholders' Equity
	(In Thousands)						
Balances at January 1, 2004	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
Reclassification of hedges to earnings, net of tax	—	—	—	—	72,620	—	72,620
Change in fair value of hedges, net of tax	—	—	—	—	(90,889)	—	(90,889)
Decrease in unfunded postretirement benefits, 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	1,444,367	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	(200)	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
Reclassification of hedges to earnings, net of tax	—	—	—	—	144,290	—	144,290
Change in fair value of hedges, net of tax	—	—	—	—	(180,591)	—	(180,591)
Increase in unfunded postretirement benefits, 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	1,529,102	217,293	(18,220)	(50,108)	1,684,522

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (Continued)

	Common Stock		Capital Surplus	(Accumulated Deficit) Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Treasury Stock	Total Shareholders' Equity
				(In Thousands)			
Balances at December 31, 2005	64,548	6,455	1,529,102	217,293	(18,220)	(50,108)	1,684,522
Exercise of stock options	289	28	6,019	(8)	—	27	6,066
Tax benefit of stock options exercised	—	—	25	—	—	—	25
Employee stock purchase plan	28	4	741	—	—	—	745
Restricted stock issued, net of forfeitures	(6)	(1)	—	—	—	—	(1)
Retirement of treasury stock	(1,861)	(186)	(49,895)	—	—	50,081	—
Amortization of stock-based compensation	—	—	20,158	—	—	—	20,158
Tax benefit of acquired net operating losses	—	—	8,337	—	—	—	8,337
Pro rata distribution of MERI common stock to shareholders (Note 2)	—	—	(298,827)	(247,991)	7,549	—	(539,269)
Comprehensive earnings:							
Net earnings	—	—	—	168,502	—	—	168,502
Reclassification of hedges to earnings, net of tax	—	—	—	—	50,581	—	50,581
Change in fair value of hedges, net of tax	—	—	—	—	30,873	—	30,873
Decrease in unfunded postretirement benefits, net of tax	—	—	—	—	2,333	—	2,333
Foreign currency translation	—	—	—	—	1,134	—	1,134
Total comprehensive earnings							253,423
Balances at December 31, 2006	62,998	$6,300	1,215,660	137,796	74,250	—	1,434,006

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Operating activities:			
Net earnings	$ 168,502	151,568	122,551
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation and depletion	266,881	368,679	354,092
Accretion of asset retirement obligations	7,096	17,317	17,251
Impairments	3,668	2,924	6,261
Unrealized (gains) losses on derivative instruments, net	(83,629)	21,373	1,088
Cash settlements on derivatives acquired in business combinations	—	14,704	8,833
Stock-based compensation expense	13,240	763	122
Unrealized foreign currency exchange loss	3,931	—	—
Deferred income tax expense	90,004	89,860	76,506
Other, net	5,899	(13,593)	(9,277)
Changes in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	(640)	(15,350)	32,754
Other current assets	(39,860)	(25,858)	(7,610)
Accounts payable	9,200	9,528	(43,456)
Accrued interest and other current liabilities	(21,814)	6,650	8,898
Net cash provided by operating activities	422,478	628,565	568,013
Investing activities:			
Capital expenditures for property and equipment:			
Acquisition, exploration, and development costs	(894,448)	(679,974)	(541,000)
Other fixed assets	(21,950)	(10,743)	(2,829)
Proceeds from sales of assets	6,507	24,046	97,933
Sale of goodwill and contract value	—	—	8,493
Other, net	—	(4,559)	(18,498)
Net cash used by investing activities	(909,891)	(671,230)	(455,901)
Financing activities:			
Proceeds from bank borrowings	3,410,778	2,351,741	2,025,074
Repayments of bank borrowings	(3,280,574)	(2,350,000)	(2,165,646)
Proceeds from term loans, net of issuance costs	367,706	—	—
Repayments of bank debt assumed in acquisitions	—	(35,000)	(66,354)
Proceeds from Spin-off	21,670	—	—
Proceeds from the exercise of options and warrants and from employee stock purchase plan	6,811	43,377	22,894
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
Cash settlements on derivatives acquired in business combinations	—	(14,704)	(8,833)
Other, net	(12,559)	(10)	1,167
Net cash provided (used) by financing activities	513,832	(4,596)	(68,269)
Effect of exchange rate changes on cash	(486)	(759)	(101)
Net increase (decrease) in cash and cash equivalents	25,933	(48,020)	43,742
Cash and cash equivalents at beginning of year	7,231	55,251	11,509
Cash and cash equivalents at end of year	$ 33,164	7,231	55,251
Cash paid during the year for:			
Interest	$ 76,979	66,140	64,687
Income taxes	5,590	7,900	3,790

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2006, 2005, and 2004

(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 earnings.

Certain amounts in prior years' financial statements have been reclassified to conform to the 2006 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

The Company considers all debt instruments with original maturities of three months or less to be cash equivalents.

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

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 2006, 2005, and 2004, 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. For the years ended December 31, 2006, 2005, and 2004 Forest capitalized $31.8 million, $26.5 million, and $24.0 million of general and administrative costs, respectively. Interest costs related to significant unproved properties which are under development are also capitalized to oil and gas properties. During 2006 and 2005, the Company capitalized approximately $3.7 million and $.9 million of interest expense attributed to unproved properties. No interest was capitalized in 2004.

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 on its proved oil and gas assets. 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, 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. Should the net capitalized costs for a cost center exceed the sum of the components noted above, an impairment charge would be recognized to the extent of the excess capitalized costs. There were no provisions for impairment of proved oil and gas properties in 2006, 2005, or 2004. However, at September 30, 2006, the spot price that Forest used for its Canadian natural gas in computing its cost center ceiling was temporarily depressed to a level at which Forest's capitalized costs in its Canadian cost center would have exceeded the cost center ceiling, as described above, by approximately $66.9 million. Subsequent to September 30, 2006 and before the release of the quarterly financial statements, the spot price of Canadian natural gas increased to levels such that Forest's Canadian cost center ceiling exceeded its capitalized costs. As such, no impairment adjustment to the Canadian cost center was necessary as of September 30, 2006.

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 15 years.

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

Asset Retirement Obligations

Forest records estimated future asset retirement obligations pursuant to the provisions of Statement of Financial Accounting Standards 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 related long-lived asset. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period to its present value. Capitalized costs are depleted as a component of the full cost pool using the units-of-production method. Forest'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.

The following table summarizes the activities for the Company's asset retirement obligations for the years ended December 31, 2006 and 2005:

	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In Thousands)	
Asset retirement obligations at beginning of period	$ 211,554	210,176
Accretion expense	7,096	17,317
Liabilities incurred	3,033	4,739
Liabilities settled	(6,652)	(32,711)
Liabilities included in the Spin-off	(150,182)	—
Liabilities assumed	1,009	705
Revisions of estimated liabilities	(1,687)	10,890
Impact of foreign currency exchange rate	(69)	438
Asset retirement obligations at end of period	64,102	211,554
Less: current asset retirement obligations	2,694	33,329
Long-term asset retirement obligations	$ 61,408	178,225

Financial Instruments

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, derivative instruments and accounts receivable. The Company's cash equivalents and derivative instruments 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 fair values of derivative instruments were based on quoted market prices and option pricing models. 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 the Company's senior notes and term loan facilities were estimated based on quoted market prices, if available, or quoted market prices of comparable instruments. The carrying values and fair values of the Company's debt instruments (other than its credit facilities) are summarized below for the periods presented.

	December 31, 2006		December 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In Thousands)			
8% Senior Notes due 2008	$268,200	271,294	270,408	276,263
Term Loan Facility—first lien due 2010	250,000	251,250	—	—
Term Loan Facility—second lien due 2011	125,000	130,000	—	—
8% Senior Notes due 2011	295,610	296,400	297,742	311,363
7¾% Senior Notes due 2014	161,305	152,625	162,851	155,625

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 its entitled share of gas proceeds. Since there is a ready market for natural gas, the Company sells the majority of its products soon after production at various locations, including the wellhead, 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, 2006, the Company had a net gas imbalance payable of $.5 million and at December 31, 2005, the Company had a net gas imbalance receivable of $4.0 million.

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 2006, sales to two purchasers were approximately 13%, and 12% of total revenue, in 2005, there were no purchasers who exceeded 10% of total revenue, and in 2004, sales to four purchasers were approximately 15%, 11%, 11%, and 11% of total revenue.

Accounts Receivable

The components of accounts receivable include the following:

	December 31, 2006	December 31, 2005
	(In Thousands)	
Oil and gas sales	$ 89,082	136,973
Joint interest billings	27,891	38,595
Other	8,814	4,103
Allowance for doubtful accounts	(341)	(1,547)
Total accounts receivable	$125,446	178,124

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

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 tax benefits 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 end-of-period 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 of the exchange rates for the period.

During 2006 and 2004, Forest realized approximately $.3 million and $4.7 million, respectively, of foreign currency exchange gains in connection with the repayment of intercompany debt and intercompany advances denominated in U.S. dollars.

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

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. Diluted earnings per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of stock options, unvested restricted stock grants, unvested phantom stock units, and warrants. The following sets forth the calculation of basic and diluted earnings per share for the periods presented:

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands, Except Per Share Amounts)		
Earnings from continuing operations	$166,080	151,568	123,126
Income (loss) from discontinued operations, net of tax	2,422	—	(575)
Net earnings	$168,502	151,568	122,551
Weighted average common shares outstanding during the period	62,226	61,405	56,925
Add dilutive effects of stock options, unvested restricted stock grants, and unvested phantom stock units	1,205	1,145	384
Add dilutive effects of warrants	—	328	780
Weighted average common shares outstanding, including the effects of dilutive securities	63,431	62,878	58,089
Basic earnings per common share:			
From continuing operations	$ 2.67	2.47	2.16
From discontinued operations	.04	—	(.01)
Basic earnings per common share	$ 2.71	2.47	2.15
Diluted earnings per common share:			
From continuing operations	$ 2.62	2.41	2.12
From discontinued operations	.04	—	(.01)
Diluted earnings per common share	$ 2.66	2.41	2.11

Stock-Based Compensation

Prior to January 1, 2006, the Company accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, *"Accounting for Stock Issued to Employees"*, and related interpretations. Under APB Opinion No. 25, no compensation expense was recognized for stock options issued to employees if the grant price equaled or was above the market price on the date of the option grant. Effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 123 (Revised), *"Share-Based Payment"* ("SFAS 123(R)") using the modified prospective method. Under this method, compensation cost is recorded for all unvested stock options, restricted stock, and phantom stock units beginning in the period of adoption and prior period financial statements are not restated. Under the fair value recognition provisions of SFAS 123(R), stock-based compensation is measured at the grant date based on the value of the awards and the value is recognized on a straight-line basis over the requisite service period (usually the vesting period).

Treasury Stock

In May 2006, Forest retired its treasury stock. The Company had historically accounted for treasury stock acquisitions using the cost method. Under this method, for reissuance of treasury stock, to the extent

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

that the reissuance price was more than the cost, the excess was recorded as an increase to capital surplus. If the reissuance price was less than the cost, the difference was also recorded to capital surplus to the extent there was a cumulative treasury stock paid in capital balance.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes, term loans, and our revolving bank credit facilities. The remaining unamortized debt issue costs at December 31, 2006 and 2005 totaled $13.0 million and $7.5 million, respectively, and are being amortized over the life of the respective debt instruments.

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.

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) during the last three years include: foreign currency gains (losses) related to the translation of the assets and liabilities of the Company's Canadian operations; changes in the unfunded postretirement benefits; and unrealized gains (losses) related to the changes in fair value of derivative instruments designated as cash flow hedges.

The components of accumulated other comprehensive earnings (loss) for the years ended December 31, 2006, 2005, and 2004 are as follows:

	Foreign Currency Translation	Unfunded Postretirement Benefits[1]	Unrealized Gain (Loss) on Derivative Instruments, Net[1]	Accumulated Other Comprehensive Income (Loss)
	(In Thousands)			
Balance at January 1, 2004	$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)
2006 activity	1,134	2,333	89,003	92,470
Balance at December 31, 2006	$80,547	(6,297)	—	74,250

(1) Net of tax.

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

Impact of Recently Issued Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, *"Accounting for Uncertainty in Income Taxes," an interpretation of FAS 109, "Accounting for Income Taxes"* ("FIN 48"), to create a single model to address accounting for uncertainty in income tax positions. FIN 48 clarifies the accounting for income taxes, by prescribing a minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Company will adopt FIN 48 as of January 1, 2007, as required. The cumulative effect of adopting FIN 48 will be recorded in retained earnings and other accounts as applicable. The Company has not determined the effect, if any, the adoption of FIN 48 will have on the Company's financial position or results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, "*Fair Value Measurements*" ("SFAS No. 157"). This statement clarifies the definition of fair value, establishes a framework for measuring fair value, and expands the disclosures on fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We have not determined the effect, if any, the adoption of this statement will have on our financial position or results of operations.

In February 2007, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities*" ("SFAS 159"). This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this Statement permits all entities to choose to measure eligible items at fair value at specified election dates. SFAS 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. We have not determined the effect, if any, the adoption of this statement will have on our financial position or results of operations .

(2) ACQUISITIONS AND DIVESTITURES:

Acquisitions

Subsequent Event—Pending Acquisition of Houston Exploration

On January 7, 2007, Forest announced it had entered into a definitive agreement and plan of merger pursuant to which The Houston Exploration Company ("Houston Exploration") will merge with and into Forest in a stock and cash transaction totaling approximately $1.5 billion plus the assumption of debt. Houston Exploration is an independent natural gas and oil producer engaged in the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America with operations in the following four producing areas in the United States: South Texas, East Texas, the Arkoma Basin of Arkansas, and the Uinta and DJ Basins in the Rocky Mountains. The boards of directors of Forest and Houston Exploration have each unanimously approved the transaction. The transaction is subject to regulatory approvals and other customary conditions, as well as both Forest shareholder and Houston Exploration stockholder approvals. Forest management and its board of directors will continue in their current positions with Forest following the completion of the merger. The merger is expected to close in the second quarter of 2007.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

Under the terms of the merger agreement, Houston Exploration stockholders are to receive total consideration equal to 0.84 shares of Forest common stock and $26.25 in cash for each share of Houston Exploration common stock outstanding. This represents estimated merger consideration of 23.6 million shares of Forest common stock and cash of approximately $740 million, or $52.47 per share, to be received by the Houston Exploration stockholders (based on the closing price of Forest's common stock on January 5, 2007 and the number of shares of Houston Exploration common stock outstanding on January 4, 2007 and subject to increase in the event that any additional shares of Houston Exploration common stock are issued prior to the merger closing date in connection with the exercise of outstanding stock options pursuant to the terms of the merger agreement). The actual amount of total cash and stock consideration to be received by each Houston Exploration stockholder will be determined by elections, an equalization formula and a proration procedure. It is anticipated that the transaction will be tax free to Houston Exploration and the stock portion of the consideration will be received tax free by its stockholders. The cash component of the acquisition is expected to be financed under an amended and restated revolving credit facility of up to $1.4 billion for which JPMorgan Chase Bank, N.A. has provided us a commitment letter.

Cotton Valley Acquisition

On March 31, 2006, Forest completed the acquisition of oil and gas properties located primarily in the Cotton Valley trend in East Texas. Forest paid approximately $255 million, as adjusted to reflect an economic effective date of February 1, 2006, for properties with an estimated 110 Bcfe of estimated proved reserves (unaudited) at the time the acquisition was announced in February 2006 and production that averaged 13 MMcfe per day (unaudited) in January 2006. Forest acquired approximately 26,000 net acres (unaudited) in the fields, of which approximately 14,000 net acres (unaudited) were undeveloped. Forest funded this acquisition utilizing its bank credit facilities.

Buffalo Wallow Acquisition

On April 1, 2005, Forest purchased a private company whose primary assets were located in the Buffalo Wallow field in Texas and included 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.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

The total 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)
Total cash consideration	$196,645

Goodwill of $23.0 million was 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 U.S. geographical business segment. 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 Southern United States, Western United States, 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 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.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

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) was 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 U.S. and Canadian geographical business segments. The principal factor that contributed to the recognition of goodwill was opportunities for cost savings through administrative and operational synergies.

Divestitures

Spin-off and Merger 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 dividend, which consisted of a pro rata spin-off (the "Spin-off") of all outstanding shares of Forest Energy Resources, Inc. (hereinafter known as Mariner Energy Resources, Inc. or "MERI"), 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, MERI was merged with a subsidiary of Mariner Energy, Inc. ("Mariner") (the "Merger"). Mariner's common stock commenced trading on the New York Stock Exchange on March 3, 2006.

The Spin-off was a tax-free transaction for federal income tax purposes. Prior to the Merger, as part of the Spin-off, MERI paid Forest approximately $176.1 million. The $176.1 million was drawn on a newly created bank credit facility established by MERI immediately prior to the Spin-off. This credit facility and associated liability were included in the Spin-off. Subsequent to the closing, Forest received additional net cash proceeds of $21.7 million from MERI for a total of $197.8 million. As of February 27, 2007, in accordance with the transaction agreements, Forest and MERI had submitted post-closing adjustments from which Forest has determined it owed MERI approximately $5.8 million as of December 31, 2006, which is subject to further adjustment.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

The table below sets forth the effect of the Spin-off on the Company's balance sheet:

	Change in Balance Sheet Accounts (In Thousands)
Assets (Increase/(Decrease))	
Cash	$ (10)
Accounts receivable—Due from MERI	15,166
Accounts receivable—third parties	(54,078)
Other current assets	(44,837)
Proved oil and gas properties, net of accumulated depletion	(1,033,289)
Unproved oil and gas properties	(38,523)
Other assets	(7,919)
Liabilities and Shareholders' Equity ((Increase)/Decrease)	
Current liabilities	96,142
Derivative instruments	17,087
MERI credit facility	176,102
Asset retirement obligations	150,182
Deferred income taxes	184,483
Other liabilities	225
Accumulated other comprehensive income	(7,549)
Net decrease to capital surplus and retained earnings	$ (546,818)

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. As a result of the sale, ProMark's results of operations were reported as discontinued operations in the historical financial statements. Under the terms of the purchase and sale agreement, Forest may receive additional contingent consideration over a period of five years through February 2009. During the year ended December 31, 2006, Forest recognized an additional $3.6 million contingent payment ($2.4 million net of tax), which has been reflected as income from discontinued operations in the Consolidated Statements of Operations. The following table sets forth the components of loss from the discontinued operations for the year ended December 31, 2004:

	Year Ended December 31, 2004 (In Thousands)
Marketing revenue, net	$ 597
General and administrative expense	(280)
Interest expense	(2)
Other expense	(166)
Current income tax expense	(2)
Deferred income tax expense	(722)
Loss from discontinued operations, net of tax	$(575)

(3) PROPERTY AND EQUIPMENT:

Net property and equipment at December 31, 2006 and 2005 consists of the following:

	2006	2005
	(In Thousands)	
Oil and gas properties:		
Proved	$ 4,751,171	5,957,805
Unproved	261,259	275,684
Accumulated depletion	(2,265,018)	(3,059,031)
Net oil and gas properties	2,747,412	3,174,458
Other property and equipment:		
Furniture and fixtures, computer hardware and software, and other equipment	75,018	58,087
Accumulated depreciation and amortization	(32,504)	(32,527)
Net other property and equipment	42,514	25,560
Total net property and equipment	$ 2,789,926	3,200,018

The following table sets forth a summary of oil and gas property costs not being depleted at December 31, 2006, by the year in which such costs were incurred:

	Total	2006	2005	2004	2003 and Prior
			(In Thousands)		
United States:					
Acquisition costs	$ 68,371	42,454	20,463	5,446	8
Exploration costs	81,316	64,364	13,291	1,167	2,494
Total United States	149,687	106,818	33,754	6,613	2,502
Canada:					
Acquisition costs	25,169	—	3,523	7,214	14,432
Exploration costs	27,865	21,409	1,299	35	5,122
Total Canada	53,034	21,409	4,822	7,249	19,554
International:					
Acquisition costs	740	—	—	—	740
Exploration costs	57,798	6,035	2,315	1,879	47,569
Total International	58,538	6,035	2,315	1,879	48,309
Total	$261,259	134,262	40,891	15,741	70,365

The majority of the United States and Canada unproved oil and gas property costs, or those not being depleted, relate to oil and gas property acquisitions discussed in Note 2 as well as work-in-progress on various exploration projects. The Company expects that substantially all of its unproved property costs in the U.S. and Canada as of December 31, 2006 will be reclassified to proved properties within five years. Forest also holds interests in various projects located outside North America. Costs related to these international interests of $58.5 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 international costs not being amortized. In 2006, the Company continued to pursue commercial development of the Ibhubesi field discovery in South Africa. The Company also filed a production right application and also continued efforts toward securing gas contracts for the Ibhubesi field.

(4) DEBT:

Components of debt are as follows:

	December 31, 2006				December 31, 2005			
	Principal	Unamortized Premium (Discount)	Other[2]	Total	Principal	Unamortized Premium (Discount)	Other[2]	Total
				(In Thousands)				
U.S. Credit Facility	$ 23,000	—	—	23,000	97,000	—	—	97,000
Canadian Credit Facility	84,094	—	—	84,094	56,806	—	—	56,806
Term Loan Facilities[1]	375,000	—	—	375,000	—	—	—	—
8% Senior Notes due 2008	265,000	(146)	3,346	268,200	265,000	(244)	5,652	270,408
8% Senior Notes due 2011	285,000	6,458	4,152	295,610	285,000	7,750	4,992	297,742
7¾% Senior Notes due 2014	150,000	(1,751)	13,056	161,305	150,000	(1,990)	14,841	162,851
Total debt	1,182,094	4,561	20,554	1,207,209	853,806	5,516	25,485	884,807
Less: current portion of long-term debt	2,500	—	—	2,500	—	—	—	—
Long-term debt	$1,179,594	4,561	20,554	1,204,709	853,806	5,516	25,485	884,807

(1) In December 2006, Forest's wholly-owned subsidiaries, Forest Alaska and Forest Holding, entered into term loan financing arrangements in the aggregate principal amount of $375 million. The financing is comprised of two term loan facilities, including a $250 million first lien credit agreement and a $125 million second lien credit agreement. The term loans mature in December 2010 and December 2011, respectively, and are non-recourse to Forest.

(2) 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 is 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, availability under the credit facilities may, at Forest's election, be governed by certain financial covenants. Alternatively, if Forest's senior unsecured long-term debt 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 September 29, 2006, the syndicate of banks approved a Global Borrowing Base of $900 million; however, Forest did not elect to change the Global Borrowing Base allocation and the U.S. allocated borrowing base was kept at $500 million and the Canadian allocated borrowing base was kept at $100 million.

At December 31, 2006, there were outstanding borrowings of $23.0 million under the U.S. credit facility at a weighted average interest rate of 8.5%, and there were outstanding borrowings of $84.1 million under the Canadian credit facility at a weighted average interest rate of 5.9%. Forest also had used the credit facilities for approximately $3.5 million in letters of credit, leaving an unused borrowing amount under the Global Borrowing Base of approximately $489.4 million at December 31, 2006.

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. 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.

On January 5, 2007, Forest, J.P. Morgan Securities Inc. and JPMorgan Chase Bank, N.A. entered into a commitment letter and fee letter with respect to the financing of the merger with Houston Exploration and the related transactions and the refinancing of certain of Forest's existing debt. The commitment letter, which is subject to customary conditions, provides for a commitment of an aggregate of up to $1.4 billion in financing under a five-year amended and restated revolving credit facility. Initially, we anticipate the commitments for the amended and restated U.S. and Canadian credit facilities will consist of an up to $1.25 billion U.S. facility and an up to $150 million Canadian facility. We expect the terms of the amended and restated credit facilities to be substantially similar to those of the existing credit facilities. We expect to finance the cash portion of the merger consideration, which is expected to be approximately $740 million in cash (based on the outstanding shares of Houston Exploration common stock on January 4, 2007 and subject to increase), through borrowings under these amended and restated credit facilities. Forest also expects to use these credit facilities to pay for related merger costs and expenses and for general corporate purposes following the merger. The commitment letter expires April 30, 2007 and is subject to customary closing conditions.

(4) DEBT: (Continued)

Term Loan Facilities

On December 8, 2006, Forest, through its wholly-owned subsidiaries Forest Alaska Operating LLC ("Forest Alaska") and Forest Alaska Holding LLC ("Forest Holding"), issued, on a non-recourse basis to Forest, term loan financing facilities in the aggregate principal amount of $375 million. The issuance was comprised of two term loan facilities, including a $250 million first lien credit agreement and a $125 million second lien credit agreement (together the "Credit Agreements"). The loan proceeds were used to fund a $350 million distribution to Forest, which Forest used to pay down its U.S. credit facility, and to provide Forest Alaska working capital for its operations and pay transaction fees and expenses. Interest on the loans are based on an adjusted LIBO rate ("LIBOR") (LIBOR plus 3.50% under the first lien credit agreement and LIBOR plus 6.50% under the second lien credit agreement) or on a rate based on the federal funds rate (federal funds rate plus 3.0% under the first lien credit agreement and federal funds rate plus 6.0% under the second lien credit agreement), at the election of Forest Alaska. The loans under the first lien agreement will become due on December 8, 2010 and the loans under the second lien agreement will become due on December 8, 2011.

Partial repayments on the loans outstanding under the first lien agreement are due at the end of each calendar quarter, while the loans under the second lien agreement are scheduled for repayment on the maturity date. In addition, Forest Alaska is obligated to make mandatory prepayments annually using its excess cash flow and the proceeds associated with certain equity issuances, asset sales, and incurrence of additional indebtedness. Under certain circumstances involving a change in control involving Forest Holding or Forest Alaska, the credit agreements also require Forest Alaska to offer to repurchase outstanding loans and purchase loans put to it by the lenders and, depending on the date of any such repurchase, the repurchase price may include a premium. Upon an event of default, a majority of the lenders under each of the Credit Agreements may request the agent to declare the loans immediately payable. Under certain circumstances involving insolvency, the loans will automatically become immediately due and payable.

The Credit Agreements include terms and covenants that place limitations on certain types of activities that may be conducted by Forest Alaska and Forest Holding. The terms include restrictions or requirements with respect to additional debt, liens, investments, hedging activities, acquisitions, dividends, mergers, sales of assets, transactions with affiliates, and capital expenditures. In addition, the Credit Agreements include financial covenants addressing limitations on present value to total debt and first lien debt, interest coverage and leverage ratios.

8% Senior Notes Due 2008

In June 2001, Forest issued $200 million in principal amount of 8% Senior Notes due in June 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).

(4) DEBT: (Continued)

7¾% Senior Notes Due 2014

In April 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). The 7¾% Notes are redeemable, at the option of the Company, at any time on or after May 1, 2007 at the approximate redemption rates set forth below, plus accrued and unpaid interest:

Year	Redemption Rate
2007	103.9%
2008	102.6%
2009	101.3%
2010 and thereafter	100.0%

Principal Maturities

Principal maturities of debt at December 31, 2006 are as follows (in thousands):

2007	$ 2,500
2008	267,500
2009	109,594
2010	242,500
2011	410,000
Thereafter	150,000

(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 table below sets forth the provision for income taxes from continuing operations for the periods presented.

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Current:			
Federal	$ 1,341	3,738	980
Foreign	140	238	297
State	645	(478)	1,683
	2,126	3,498	2,960
Deferred:			
Federal	77,445	55,608	60,776
Foreign	3,643	24,310	9,852
State, net	7,689	9,942	5,156
	88,777	89,860	75,784
	$90,903	93,358	78,744

The Company's current income tax expense for the periods presented was due primarily to federal alternative minimum tax and to Alaska state income taxes. Deferred income taxes generally result from recognizing income and expenses at different times for financial and tax reporting. In the U.S., the largest differences are the tax effects of book recognition of unrealized gains and losses with respect to derivative instruments and the capitalization of certain development, exploration, and other costs under the full cost method of accounting. In Canada, differences result in part from accelerated cost recovery of oil and gas capital expenditures for tax purposes.

(5) INCOME TAXES: (Continued)

Income from continuing operations before income taxes and discontinued operations consists of the following for the periods presented:

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands)		
United States federal	$211,785	168,024	174,398
Foreign	45,198	76,902	27,472
	$256,983	244,926	201,870

A reconciliation of income tax computed by applying the United States statutory federal income tax rate is as follows:

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Federal income tax at 35% of income before income taxes and discontinued operations	$ 89,944	85,724	70,655
State income taxes, net of federal income tax benefits	7,616	5,759	5,140
Change in the valuation allowance for deferred tax assets	(1,464)	(5,460)	1,029
Effect of differing tax rates in Canada	(160)	1,537	2,440
Effect of taxable dividends repatriated under Section 965 of the I.R.C.	—	4,275	—
Effect of Canadian statutory rate reductions	(12,292)	(3,129)	(2,388)
Effect of state statutory rate reductions	(5,706)	—	—
Effects related to the Spin-off	7,209	—	—
Other	5,756	4,652	1,868
Total income tax expense	$ 90,903	93,358	78,744

(5) INCOME TAXES: (Continued)

The components of the net deferred tax liability by geographical segment at December 31, 2006 and 2005 are as follows:

	December 31, 2006		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Allowance for doubtful accounts	$ 487	—	487
Investment in equity affiliate	1,378	—	1,378
Accrual for post retirement benefits	4,415	—	4,415
Stock-based compensation accruals under SFAS 123(R)	2,155	—	2,155
Net operating loss carryforwards	157,084	621	157,705
Capital loss carryforward	113	3,891	4,004
Depletion carryforward	7,455	—	7,455
Alternative minimum tax credit carryforward	3,478	—	3,478
Other	9,762	969	10,731
Total gross deferred tax assets	186,327	5,481	191,808
Less valuation allowance	(27,036)	(2,642)	(29,678)
Net deferred tax assets	159,291	2,839	162,130
Deferred tax liabilities:			
Property and equipment	(264,137)	(78,786)	(342,923)
Unrealized losses on derivative contracts, net	(24,795)	—	(24,795)
Other	—	(1,276)	(1,276)
Total gross deferred tax liabilities	(288,932)	(80,062)	(368,994)
Net deferred tax liabilities	$ (129,641)	(77,223)	(206,864)

	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)

The net deferred tax liabilities are reflected in the Consolidated Balance Sheets as follows:

	December 31, 2006		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax liabilities	$ (14,907)	—	(14,907)
Non-current deferred tax liabilities	(114,734)	(77,223)	(191,957)
Net deferred tax liabilities	$(129,641)	(77,223)	(206,864)

	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)

U.S. federal net operating loss carryforwards at December 31, 2006 were approximately $447.9 million. Of this amount, approximately $186.5 million was acquired by the Company in a merger that occurred in 2000 and approximately $38.7 million was acquired by the Company in its acquisitions of other corporate entities in 2004 and 2005. The Company's federal net operating losses are scheduled to expire in years 2006 through 2024.

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. The Company has established a valuation allowance against its net operating loss carryforwards in the amount of $24.2 million, recognizing the effects of Section 382 on its ability to ever realize these carryforwards.

The net changes in the total valuation allowance for the years ended December 31, 2006, 2005, and 2004 were as follows:

	2006	2005	2004
		(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	$ (8,337)	(36,608)	(4,044)
Decrease in the valuation allowance for net expiring operating loss carryforwards	(9,967)	(3,483)	(25,313)
Other decreases in the valuation allowance for deferred tax assets	(1,465)	(2,443)	—
Net decrease in the valuation allowance	$(19,769)	(42,534)	(29,357)

$18.4 million of the decrease in valuation allowance for deferred tax assets in 2006 relates to tax loss carryforwards of an acquired subsidiary which were previously provided against. $10 million of this amount relates to tax loss carryforwards that expired unused in 2005. In 2006, the Company determined that it was more likely than not that $8.4 million would be realized in the future and this amount was released with a corresponding adjustment to capital surplus. The other decreases in the valuation allowance of $1.4 million relate to adjustments to state and Canadian tax loss carryforwards.

(5) INCOME TAXES: (Continued)

Though not included in the tables or discussion above, the Company has a net deferred tax asset of $2.8 million in international locations. The Company has, in prior years, established a valuation allowance equal to the $2.8 million net deferred tax asset as the Company currently does not have production in the related international locations. The net deferred tax asset is composed of a deferred tax asset related to loss carryforwards (with carryover periods ranging from 5 years to an indefinite period) in the amount of $18.6 million, net of a deferred tax liability related to property and equipment of $15.8 million.

The Alternative Minimum Tax ("AMT") credit carryforward available to reduce future U.S. federal regular taxes aggregated $3.5 million at December 31, 2006. This amount may be carried forward indefinitely.

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 $219 million ($255 million CDN) at December 31, 2006. The Canadian tax pools include approximately $44 million ($52 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:

	2006	2005
	(In Thousands of Canadian Dollars)	
Canadian capital cost allowance (deductible at 4% - 45% annually)	$ 76,051	56,818
Canadian development expense (deductible at 30% annually)	130,792	86,881
Canadian exploration expense (deductible at 100% annually)	1,704	44,273
Canadian oil and gas property expense (deductible at 10% annually)	46,387	41,970
	$254,934	229,942

Other Canadian tax pools and loss carryforwards available to reduce future Canadian federal income taxes were approximately $21.4 million ($24.9 million CDN) at December 31, 2006, of which $19.3 million may be carried forward indefinitely.

The Company's Canadian operations generated book income (after tax) of approximately $45 million during 2006. As of December 31, 2006, the Company's Canadian operations had reported accumulated undistributed book earnings of approximately $81 million. The Company has not provided deferred tax liabilities with respect to U.S. income tax or Canadian withholding taxes related to these undistributed earnings. During 2006, all cash flow generated in Canada was reinvested in Canadian capital expenditures. Based on its current plans, the Company intends that future cash flows generated by Canadian operations will continue to be reinvested in Canadian exploration, development or acquisition activities or utilized to satisfy external and intercompany debt of the Canadian operations. Should the Company distribute Canadian earnings, we may be subject to U.S. income taxes and Canadian withholding taxes. It is not practicable to estimate the amount of such taxes that may be payable if such a distribution occurs. The Company currently has no foreign tax credits to offset such taxes.

(6) SHAREHOLDERS' EQUITY:

Common Stock

At December 31, 2006, the Company had 200 million shares of common stock ("Common Stock"), par value $.10 per share, authorized.

(6) SHAREHOLDERS' EQUITY: (Continued)

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.

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, 2006 and 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 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 year ending December 31, 2004, warrants totaling 267,508 were exercised to purchase 162,901 shares of Common Stock.

(7) STOCK-BASED COMPENSATION:

Prior to January 1, 2006, the Company accounted for stock-based compensation using the intrinsic value method prescribed in APB Opinion No. 25 and related interpretations. Under APB Opinion No. 25, no compensation expense was recognized for stock options issued to employees if the grant price equaled or was above the market price on the date of the option grant. Effective January 1, 2006, the Company adopted the provisions of SFAS 123(R) using the modified prospective method. Under this method, compensation cost is recorded for all unvested stock options, restricted stock, and phantom stock units beginning in the period of adoption and prior period financial statements are not restated. Under the fair value recognition provisions of SFAS 123(R), stock-based compensation is measured at the grant date based on the value of the awards and the value is recognized on a straight-line basis over the requisite service period (usually the vesting period).

The table below sets forth total stock-based compensation recorded during 2006 under the provisions of SFAS 123(R), the remaining unamortized amounts and the weighted average amortization period remaining as of December 31, 2006. Approximately $9.7 million of the $22.0 million of total stock-based compensation for 2006 was attributable to a partial settlement of the Company's restricted stock awards and phantom stock unit awards in connection with the Spin-off.

(7) STOCK-BASED COMPENSATION: (Continued)

	Stock Options	Restricted Stock	Phantom Stock Units	Total[1]
		(In Thousands)		
Year ended December 31, 2006:				
Total stock-based compensation costs	$ 5,348	14,551	1,890	21,789
Less: stock-based compensation costs capitalized	(1,645)	(5,279)	(1,194)	(8,118)
Stock-based compensation costs expensed	$ 3,703	9,272	696	13,671
Unamortized stock-based compensation costs as of December 31, 2006	$ 6,006	10,725	1,867[2]	18,598
Weighted average amortization period remaining	1.5 years	1.8 years	2.1 years	1.7 years

(1) The Company also maintains an employee stock purchase plan (which is not included in the table above) under which $.3 million of compensation cost was recognized for the year ended December 31, 2006 under the provisions of SFAS 123(R).

(2) Based on the closing price of the Company's Common Stock on December 31, 2006.

SFAS 123(R) required the Company to estimate forfeitures in calculating the cost related to stock-based compensation as opposed to recognizing forfeitures and the corresponding reduction in expense as the forfeitures occur. The cumulative adjustment recorded related to this change of approximately $.1 million was recorded as a reduction in general and administrative expense and capitalized oil and gas properties during 2006 and was not presented separately in the Consolidated Statement of Operations. The impact of adopting SFAS 123(R) as of January 1, 2006 resulted in a decrease to net earnings of approximately $1.9 million, or $.03 per basic and diluted share for the year ending December 31, 2006.

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 Common Stock that the Company may issue under the 2001 Plan may not exceed 5.0 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, 2006, the Company had 667,957 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 were 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, 2006, 2005, and 2004. During 2006 the number of shares and the exercise price of the outstanding stock options were adjusted so that the fair value of each award was the same immediately before and after the Spin-off, in accordance with the anti-dilution provisions in the 2001 Plan and 1996 Plan.

(7) STOCK-BASED COMPENSATION: (Continued)

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)[1]	Number of Shares Exercisable
Outstanding at January 1, 2004	3,465,429	$25.51	$12,146	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	18,024	1,841,439
Granted at fair value	180,700	38.82		
Exercised	(1,078,067)	26.32	13,469	
Cancelled	(295,210)	27.71		
Outstanding at December 31, 2005	2,578,235	27.78	45,889	1,348,599
Granted	—	—		
Exercised	(58,337)	28.71	1,255	
Cancelled	(98,587)	30.91		
Outstanding at March 2, 2006	2,421,311	27.63	55,723	
Adjustment to give effect to Spin-off	1,176,804	—		
Granted	55,000	36.61		
Exercised	(231,470)	18.96	3,536	
Cancelled	(93,366)	20.94		
Outstanding at December 31, 2006	3,328,279	18.80	46,279	2,338,751

(1) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.

Stock options are granted at the fair market value of one share of Common Stock on the date of grant. Options granted to non-employee directors vest immediately and options granted to officers and other employees vest ratably over four years. All outstanding options had a term of ten years at the date of grant.

The fair value of each option granted in 2006, 2005, and 2004 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:

	2006	2005	2004
Expected life of options	10 years	5 years	5 years
Risk free interest rates	4.64% - 5.13%	3.64% - 4.45%	2.98% - 4.01%
Estimated volatility	45%	28%	39%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of options granted during the year	$ 23.35	$ 12.77	$ 11.64

(7) STOCK-BASED COMPENSATION: (Continued)

The following table summarizes information about options outstanding at December 31, 2006:

	Stock Options Outstanding				Stock Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)	Number Exercisable	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)
$8.41 – 16.30	671,101	5.72	$14.80	$12,027	523,522	$14.64	$ 9,422
16.44 – 16.85	812,345	6.55	16.83	12,899	521,859	16.82	8,251
16.88 – 20.02	679,923	4.69	18.88	9,398	643,523	18.94	8,812
20.19 – 20.47	23,775	7.27	20.32	294	9,288	20.39	114
20.60 – 36.95	1,141,135	7.68	22.47	11,661	640,559	22.86	6,262
$8.41 – 36.95	3,328,279	6.39	18.80	$46,279	2,338,751	18.59	$32,861

Restricted Stock and Phantom Stock Units

The following table summarizes the restricted stock and phantom stock unit activity for the years ended December 31, 2006, 2005, 2004. The grant date fair value of the restricted stock and phantom stock units was determined by reference to the average of the high and low stock price of a share of Common Stock as published by the New York Stock Exchange on the date of grant.

	Restricted Stock		Phantom Stock Units	
	Number of Shares	Weighted Average Grant Date Fair Value[1]	Number of Shares	Weighted Average Grant Date Fair Value[1]
Unvested at January 1, 2004	—	$ —	—	$ —
Awarded	95,600	29.44	—	—
Vested	—	—	—	—
Forfeited	—	—	—	—
Unvested at December 31, 2005	95,600	29.44	—	—
Awarded	548,000	45.82	72,350	46.07
Vested	(600)	30.61	—	—
Forfeited	(9,000)	30.61	—	—
Unvested at December 31, 2006	634,000	43.58	72,350	46.07
Awarded	38,200	39.24	13,900	36.24
Vested	(200)	46.07	—	—
Forfeited	(44,550)	45.95	(8,300)	46.07
Unvested at December 31, 2006	627,450	43.15	77,950	44.32

(1) These per-share fair values represent the actual grant date fair value and have not been adjusted to give effect to the Spin-off. In connection with the Spin-off, holders of restricted stock awards received 0.8093 unrestricted shares of MERI for each share of restricted stock. Accordingly, compensation cost of approximately $8.4 million was recorded in the first quarter of 2006 as a partial settlement of the restricted stock award, or approximately $13.00 per share. In addition, cash bonuses totaling $1.2 million were paid to Canadian employees in the first quarter of 2006 that held phantom stock units on that date representing the per-share value of the MERI shares received by each holder of restricted stock.

The restricted stock and phantom stock units generally vest on the third anniversary of the date of the award, but may vest earlier upon a qualifying disability, death, retirement, or a change in control of the Company in accordance with the term of the underlying agreement. The phantom stock units can be settled in cash, shares of Common Stock, or a combination of both. The phantom stock units have been accounted for as a liability within the consolidated financial statements. The Company recorded amortization of deferred stock-based compensation costs of $1.3 million and $.2 million during the years ended December 31, 2005 and 2004, respectively, related to these equity awards.

(7) STOCK-BASED COMPENSATION: (Continued)

Employee Stock Purchase Plan

The Company has 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 shares of Common Stock, up to a limit of $25,000 of Common Stock per calendar year. The ESPP currently provides for four offering periods during the year which coincide with the calendar quarters. The purchase price of a share of Common Stock purchased under the ESPP 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. As of December 31, 2006, the Company had 161,651 shares available for issuance under the ESPP.

The fair value of each stock purchase right granted under the ESPP during 2006, 2005, and 2004 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:

	2006	2005	2004
Expected option life	3 months	3 months	3 months
Risk free interest rates	4.16% - 5.08%	2.32% - 3.61%	0.93% - 1.71%
Estimated volatility	21%	26%	23%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of purchase rights granted	$9.38	$12.11	$7.91

Pro Forma Effects

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

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

(8) EMPLOYEE BENEFITS:

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 in 2004, 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. The Forest Pension Plan, the Wiser Pension Plan, and the SERP are hereinafter collectively referred to as the "Plans."

In addition to the Plans described above, Forest also provides postretirement benefits to employees in the U.S. and Canada, their beneficiaries, and covered dependents. These benefits, which consist primarily of medical benefits payable on behalf of retirees in the U.S. and Canada, are referred to as "Postretirement Benefits" throughout this Note. The postretirement benefits in both the U.S. and Canada are closed to new participants.

Investments of the Plans

The weighted average asset allocations of the Forest Pension Plan and Wiser Pension Plan at December 31, 2006 and 2005 are set for the in the following table:

	Forest Pension Plan		Wiser Pension Plan	
	2006	2005	2006	2005
Fixed income securities	33%	49%	28%	18%
Equity securities	64%	50%	67%	44%
Other	3%	1%	5%	38%
	100%	100%	100%	100%

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 targeted maximum 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.

Expected Benefit Payments

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 and the

(8) EMPLOYEE BENEFITS: (Continued)

other postretirement benefits plans in 2007 through 2011 and in the aggregate for the years 2012 through 2016 in the following amounts:

	2007	2008	2009	2010	2011	2012-2016
			(In Thousands)			
Forest Pension Plan[1]	$2,368	2,384	2,367	2,336	2,305	10,868
SERP	62	59	57	54	52	215
Wiser Pension Plan[1]	821	806	803	805	798	4,005
Postretirement benefits (U.S.)	582	572	572	594	615	2,896
Postretirement benefits (Canada)	45	48	51	55	58	336

(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.

Forest anticipates that it will make contributions in 2007 totaling $1.1 million to the Plans and $.5 million for the Postretirement Benefit plans, net of retiree contributions as applicable.

The following tables set forth the estimated benefit obligations, the fair value of the assets, and the funded status of the Plans and the Postretirement Benefit plans at December 31, 2006 and 2005. Amounts for the Forest Pension Plan, the SERP, and the Wiser Pension Plan are combined in the "Pension Benefits" columns.

	Pension Benefits		Postretirement Benefits	
	2006	2005	2006	2005
		(In Thousands)		
Benefit obligation at the beginning of the year	$42,804	40,921	10,297	11,144
Service cost	—	—	580	671
Interest cost	2,192	2,325	453	493
Actuarial (gain) loss[1]	(1,257)	2,875	(271)	(1,439)
Effect of curtailment	—	—	(2,092)	—
Benefits paid	(3,183)	(3,317)	(584)	(671)
Medicare reimbursements	—	—	7	—
Retiree contributions	—	—	68	78
Impact of foreign currency exchange rate	—	—	(1)	21
Benefit obligation at the end of the year	$40,556	42,804	8,457	10,297

(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.

(8) EMPLOYEE BENEFITS: (Continued)

Fair Value of Plan Assets

	Pension Benefits		Postretirement Benefits	
	2006	2005	2006	2005
	(In Thousands)			
Fair value of plan assets at beginning of the year	$34,472	33,405)	—	—
Actual return on plan assets	3,761	1,794	—	—
Retiree contributions	—	—	68	78
Medicare reimbursements	—	—	7	—
Employer contribution	2,565	2,590	509	593
Benefits paid	(3,183)	(3,317)	(584)	(671)
Fair value of plan assets at the end of the year	$37,615	34,472	—	—

Funded Status

	Pension Benefits		Postretirement Benefits	
	2006	2005	2006	2005
	(In Thousands)			
Excess of benefit obligation over plan assets	$ (2,941)	(8,332)	(8,457)	(10,297)
Unrecognized actuarial loss (gain)	10,422	13,920	(271)	241
Net amount recognized	$ 7,481	5,588	(8,728)	(10,056)
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability	$ (2,941)	(8,332)	(8,457)	(10,056)
Accumulated other comprehensive income—net actuarial loss (gain)	10,422	13,920	(271)	—
Net amount recognized	$ 7,481	5,588	(8,728)	(10,056)

The Company adopted the recognition provisions of SFAS No. 158, "*Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 106, and 132(R)*" and initially applied them to the funded status of its defined benefit post retirement plans as of December 31, 2006. The initial recognition of the funded status of its defined benefit post retirement plans resulted in an increase in accumulated other comprehensive income in shareholders' equity of $.1 million.

(8) EMPLOYEE BENEFITS: (Continued)

The following table sets forth the projected and accumulated benefit obligations for the pension plans compared to the fair value of the plan assets for the periods indicated.

	December 31, 2006	December 31, 2005
	(In Thousands)	
Projected benefit obligation	$40,556	42,804
Accumulated benefit obligation	40,556	42,804
Fair value of plan assets	37,615	34,472

Actuarial Assumptions and Annual Periodic Expense

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, 2006, 2005, and 2004:

	Pension Benefits			Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
			(In Thousands)			
Service cost	$ —	—	81	580	671	645
Interest cost	2,192	2,325	2,056	453	493	580
Curtailment gain[(1)]	—	—	—	(1,851)	—	—
Expected return on plan assets	(2,430)	(2,346)	(1,843)	—	—	—
Recognized actuarial loss	899	753	692	—	—	219
Amortization of prior service cost	10	—	—	—	—	—
Settlement loss	—	—	20	—	—	—
Total net periodic expense (benefit)	$ 671	732	1,006	(818)	1,164	1,444
Assumptions used to determine net periodic expense:						
Discount rate	5.32%	5.75%	6.00%	4.72% & 5.46%	5.75% & 6.00%	6.00% & 6.75%
Expected return on plan assets	7% & 8%	7% & 8%	7% & 8%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:						
Discount rate	5.64%	5.32%	5.75%	3.98% & 5.75%	4.72% & 5.46%	5.75% & 6.00%

(1) Forest recognized a $1.9 million curtailment gain in connection with the Spin-off on March 2, 2006. This gain was recorded as a reduction in general and administrative expense for the year ended December 31, 2006.

The discount rates used to determine benefit obligations 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.

The Company estimates that net periodic expense for the year ended December 31, 2007, will include expense of $.6 million resulting from the amortization of its related accumulated actuarial loss included in accumulated other comprehensive income at December 31, 2006.

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits for the U.S. Postretirement Benefits was held constant at 5.50% during 2006 and thereafter. The annual rate of increase in the per capita cost of covered health care benefits for the Canadian Postretirement Benefits was assumed to be 4% per year for the dental plan; 5% per year for Provincial health care; and 10% in 2007, 9% in 2008, 8% in 2009, 7% in 2010, 6% in 2011, and 5% thereafter for the medical plan.

(8) EMPLOYEE BENEFITS: (Continued)

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 2006:

	Postretirement Benefits	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	$ 308	(193)
Effect on postretirement benefit obligation	$1,463	(1,141)

Employee Retirement Savings Plans

Forest sponsors a qualified tax-deferred savings plan ("Retirement Savings Plan") for its employees in the U.S. 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. Effective January 1, 2004, the Company matching percentage is 7% of eligible employee compensation. Expenses associated with the Company's contributions to the Retirement Savings Plan totaled $1.9 million in 2006, $2.2 million in 2005, and $1.9 million in 2004. 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 2006, 2005 and 2004. All employees of Canadian Forest also 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 $.2 million in 2006 and $.3 million in each of 2005 and 2004.

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 Plan

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. Prior to 2006, the Company recorded a liability for matching contributions and accrued 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 $.3 million in 2006, and $.4 million in both 2005 and 2004. Beginning on January 1, 2007, the Executive Plan was amended and under the modified structure, participants may designate how deferred amounts are deemed to be invested. There are several investment options available to the participants. As a result, the fair value of the liability recorded with respect to the deferred amounts will fluctuate due to gains and losses associated with investment options selected by the participants. The fair value of amounts deferred (including accrued interest) under the Executive Plan was approximately $2.4 million and $1.9 million at December 31, 2006 and 2005, respectively.

(9) DERIVATIVE INSTRUMENTS:

Forest periodically enters into derivative instruments such as swap, basis swap, and collar agreements in order 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. Forest's commodity derivative instruments generally serve as effective economic hedges of commodity price exposure; however, various circumstances can cause commodity hedges to not qualify for cash flow hedge accounting either at the inception of the hedge or during the term of the hedge. When the criteria for cash flow hedge accounting are not met or when cash flow hedging is not elected, realized gains and losses (i.e., cash settlements) are recorded in other income and 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.

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 some of its natural gas and oil hedges during the third and fourth quarters of 2005. Additionally, as a result of the Spin-off on March 2, 2006, additional commodity swaps and collars formerly designated as cash flow hedges of offshore Gulf of Mexico production also no longer qualified for hedge accounting. Because a significant portion of the Company's derivatives no longer qualified for hedge accounting and to increase clarity in its financial statements, the Company elected to discontinue hedge accounting prospectively for all of its remaining commodity derivatives beginning in March 2006. This change in reporting has not impacted the Company's reported cash flows, although the results of operations have been affected by mark-to-market gains and losses, which fluctuate with volatile oil and gas prices. Subsequent to March 2006, the Company has recognized all mark-to-market gains and losses in earnings, rather than deferring such amounts in accumulated other comprehensive income included in shareholders' equity.

The tables below set forth, as of December 31, 2006, the quantity of oil and gas hedged under commodity swaps and collars.

	Swaps			
	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Barrels Per Day[(1)]	Weighted Average Hedged Price per Bbl
Fiscal 2007	20.0	$8.10	7,000	$70.03
Fiscal 2008	—	—	6,500	69.72
Fiscal 2009	—	—	5,500	69.76
Fiscal 2010	—	—	2,000	73.15

(1) Subsequent to December 31, 2006, Forest unwound two oil swap agreements covering 1,000 Bbl per day in 2009 and 500 Bbl per day 2010 for total proceeds of $6.9 million.

	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
Fiscal 2007	35.0	$8.76/11.70	4,000	$65.81/87.18

(9) DERIVATIVE INSTRUMENTS: (Continued)

Forest also uses basis swaps in connection with natural gas swaps in order to fix the price differential between the NYMEX Henry Hub price and the index price at which the physical gas is sold. At December 31, 2006, there were basis swaps in place covering 35.0 Bbtu per day in 2007.

As of December 31, 2006, the net fair values of the Company's derivative instruments was $66.1 million, which is presented on the Consolidated Balance Sheet as a derivative asset of $68.2 million (of which $53.2 million was classified as current) and a derivative liability of $2.1 million (of which $1.3 million was classified as current). Forest is exposed to risks associated with swap and collar agreements arising from movements in the prices of oil and natural gas and from the unlikely event of non-performance by the counterparties to the swap and collar agreements.

The table below summarizes the realized and unrealized losses Forest incurred related to its hedging activities for the periods indicated.

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Realized losses on derivatives designated as cash flow hedges[1]	$ 43,813	186,442	117,129
Realized losses (gains) on derivatives not designated as cash flow hedges[2]	23,864	35,390	(336)
Ineffectiveness recognized on derivatives designated as cash flow hedges[2]	(5,573)	5,747	(156)
Unrealized (gains) losses on derivatives not designated as cash flow hedges[2]	(78,056)	15,626	1,244
Total realized and unrealized (gains) losses recorded	$(15,952)	243,205	117,881

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

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

In January and February 2007, we entered into four additional swap agreements and one additional collar agreement to hedge a portion of expected future production attributable to the pending acquisition of Houston Exploration as summarized in the table below.

	Natural Gas (NYMEX HH)			
	Swaps		Collars	
	Bbtu per Day	Weighted Average Hedged Price per MMBtu	Bbtu per Day	Weighted Average Hedged Floor and Ceiling Price per MMBtu
April 2007 – December 2007	40.0	$7.77	—	—
Fiscal 2008	—	—	10.0	$7.75/9.57

(10) 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. As of December 31, 2006, Anschutz owned approximately 12.6% of Forest's outstanding common stock. Based on reports filed with the SEC, as of January 31, 2007, Anschutz has entered into forward sales contracts covering 7.1 million shares of Common Stock, or approximately 11.3% of Forest's outstanding common stock, that will settle in 2009 and 2010, and Anschutz retains voting rights for these shares through the settlement dates.

(10) RELATED PARTY TRANSACTIONS: (Continued)

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 27, 2007, 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.

(11) COMMITMENTS AND CONTINGENCIES:

Future rental payments for office facilities, office equipment, and well equipment under the remaining terms of non-cancelable operating leases are $3.6 million, $3.3 million, $3.3 million, $3.1 million, and $3.1 million for the years ending December 31, 2007 through 2011, respectively. Future rental payments under the remaining terms of non-cancelable operating leases for fiscal periods beyond 2011 total $12.4 million. During the years ended December 31, 2006 and 2005, the Company received approximately $.6 million and $5.0 million, respectively, 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 the lease through 2016. Amortization of lease concessions and incentives was $.5 million in 2006 and $.1 million in 2005. Remaining terms for unconditional purchase obligations consisting of firm commitments for drilling, gathering, processing and pipeline capacity are $46.1 million, $19.5 million, $10.3 million, $5.2 million and $4.6 million for the years ending December 31, 2007 through 2011, respectively.

Net rental payments applicable to exploration and development activities and capitalized to oil and gas properties were $9.4 million in 2006, $7.0 million in 2005, and $5.6 million in 2004. Net rental payments under non-cancelable operating leases charged to expense amounted to $4.1 million in 2006, $4.6 million in 2005, and $3.7 million in 2004. 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.

Houston Exploration and Forest are currently subject to an ongoing shareholder lawsuit, which could result in an injunction preventing the consummation of the merger discussed in Note 2 or significant monetary damages. Houston Exploration's directors and Forest are defendants in a shareholder lawsuit brought by the City of Monroe Employees' Retirement System (the "Plaintiff") in Houston, Texas. The Plaintiff asserts that the Houston Exploration directors breached their fiduciary duties by not pursuing a June 12, 2006 unsolicited proposal to purchase the outstanding shares of Houston Exploration common stock for $62 per share that was made by a Houston Exploration shareholder. The Plaintiff also asserts, on behalf of an uncertified class of Houston Exploration's shareholders, that the Houston Exploration directors' decision to enter into the merger agreement with Forest constituted a breach of fiduciary duties because, the Plaintiff alleges, the merger consideration being offered by Forest is inadequate. The Plaintiff asserts that Forest aided and abetted the Houston Exploration directors' alleged breach of fiduciary duties.

(11) COMMITMENTS AND CONTINGENCIES: (Continued)

At the time of the filing of these consolidated financial statements, this lawsuit is at an early stage and subject to substantial uncertainties concerning the outcome of material factual and legal issues. Accordingly, based on the current status of the litigation, we cannot currently predict the manner and timing of the resolution of the lawsuit, the likelihood of the issuance of an injunction preventing the consummation of the merger or an estimate of a range of possible losses or any minimum loss that could result in the event of an adverse verdict in the lawsuit. Furthermore, although the combined company's insurance policies following the merger should provide coverage for the claims against Houston Exploration's directors, the policies may not be sufficient to cover all costs and liabilities incurred by those directors. The current claim in the lawsuit against Forest is not covered by insurance.

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 7% of Forest's total average daily production in 2006. Canadian Forest supplied 55% of the Canadian Netback Pool sales quantity in 2006, and it is estimated that Canadian Forest will supply 79% of the Canadian Netback Pool quantity in the 2007 contract year. We expect that Canadian Forest's pro rata obligations as a gas producer will increase in 2008 and future years. In 2006, the weighted average price paid under the resale contracts was approximately 55% of market value based on the average closing AECO prices during 2006. 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.

(12) OTHER (INCOME) EXPENSE:

The components of other (income) expense, net for the years ended December 31, 2006, 2005, and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
	(In Thousands)		
Realized foreign currency exchange gain	$ (315)	—	(4,728)
Franchise taxes	1,410	1,963	1,219
Share of (income) loss of equity method investee	(2,334)	562	(1,726)
Other, net	1,135	3,722	3,056
Total other (income) expense, net	$ (104)	6,247	(2,179)

(13) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In Thousands, Except Per Share Amounts)			
2006[1]				
Revenue	$221,446	211,853	202,839	183,854
Earnings from operations	$ 57,086	81,982	79,129	54,635
Net earnings from continuing operations	$ 1,249	57,048	76,934	30,849
Net earnings	$ 3,671	57,048	76,934	30,849
Basic earnings per share from continuing operations	$ .02	.92	1.24	.49
Basic earnings per share	.06	.92	1.24	.49
Diluted earnings per share from continuing operations	.02	.90	1.21	.48
Diluted earnings per share	.06	.90	1.21	.48
2005[1]				
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

(1) Since the third quarter of 2005, net earnings from continuing operations has been subject to large fluctuations due to the discontinuance of cash flow hedge accounting as discussed in Note 9.

(14) 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, 2006, Forest conducted operations in one industry segment, that being the oil and gas exploration and production industry, and had three reportable geographical business segments: United States, 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 geographical location of operations in each business segment. The segment data presented below was prepared on the same basis as the consolidated financial statements. Effective in the first quarter of 2006, Forest ceased allocating general and administrative expenses to the business segments to correspond with its decision to monitor and evaluate general and administrative expenses at the corporate level. Effective in the third quarter of 2006, Forest decreased the number of reportable segments from five to three to correspond to the same number of cost centers under the full cost accounting rules. Segment information previously reported has been modified to conform to the current presentation.

(14) GEOGRAPHICAL SEGMENTS: (Continued)

	Oil and Gas Operations Year Ended December 31, 2006			
	United States	Canada (In Thousands)	International	Total Company
Revenue	$636,897	177,572	—	814,469
Expenses:				
Lease operating expenses	126,647	28,227	—	154,874
Production and property taxes	36,060	2,981	—	39,041
Transportation and processing costs	11,941	9,935	—	21,876
Depletion	188,073	75,366	—	263,439
Accretion of asset retirement obligations	6,046	1,004	46	7,096
Impairment and other	—	—	3,668	3,668
Earnings (loss) from operations	$268,130	60,059	(3,714)	324,475
Capital expenditures[1]	$782,945	150,955	6,984	940,884
Goodwill	$ 71,377	14,869	—	86,246

[1] Does not include estimated discounted asset retirement obligations of $2.4 million related to assets placed in service during the year ended December 31, 2006.

Information for reportable segments relates to the Company's 2006 consolidated totals as follows:

	(In Thousands)
Earnings from operations for reportable segments	$324,475
Marketing, processing, and other	5,523
General and administrative expense (including stock-based compensation)	(48,308)
Interest expense	(71,787)
Administrative asset depreciation	(3,442)
Spin-off and merger costs	(5,416)
Realized losses on derivative instruments, net	(23,864)
Unrealized gains on derivative instruments, net	83,629
Unrealized foreign currency exchange loss	(3,931)
Other income, net	104
Earnings before income taxes and discontinued operations	$256,983

	Oil and Gas Operations Year Ended December 31, 2005			
	United States	Canada (In Thousands)	International	Total Company
Revenue	$885,616	176,901	—	1,062,517
Expenses:				
Lease operating expenses	180,867	18,894	—	199,761
Production and property taxes	39,819	2,796	—	42,615
Transportation and processing costs	13,805	5,694	—	19,499
Depletion	301,536	63,335	—	364,871
Accretion of asset retirement obligations	16,323	962	32	17,317
Impairment and other	8,208	—	2,924	11,132
Earnings (loss) from operations	$325,058	85,220	(2,956)	407,322
Capital expenditures[1]	$718,641	115,019	3,688	837,348
Goodwill	$ 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.

(14) 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	$407,322
Marketing, processing, and other	9,528
General and administrative expense (including stock-based compensation)	(43,703)
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 and discontinued operations	$244,926

	Oil and Gas Operations Year Ended December 31, 2004			
	United States	Canada (In Thousands)	International	Total Company
Revenue	$799,590	110,190	—	909,780
Expenses:				
Lease operating expenses	171,299	17,862	—	189,161
Production and property taxes	31,098	1,143	—	32,241
Transportation and processing costs	13,635	3,157	—	16,792
Depletion	304,574	45,737	—	350,311
Accretion of asset retirement obligations	16,485	766	—	17,251
Impairment and other	7,040	1,764	4,125	12,929
Earnings (loss) from operations	$255,459	39,761	(4,125)	291,095
Capital expenditures[1]	$536,172	158,310	5,755	700,237
Goodwill	$ 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.

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

	(In Thousands)
Earnings from operations for reportable segments	$291,095
Marketing, processing, and other	3,118
General and administrative expense (including stock-based compensation)	(32,145)
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 and discontinued operations	$201,870

(15) 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").

(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, 2006, 2005, and 2004:

	United States	Canada	International	Total
		(In Thousands)		
2006				
Property acquisition costs:				
Proved properties	$262,534	—	—	262,534
Unproved properties	53,788	—	—	53,788
Exploration costs	155,824	99,657	6,984	262,465
Development costs	312,104	52,348	—	364,452
Total costs incurred[1][2]	$784,250	152,005	6,984	943,239
2005				
Property acquisition costs:				
Proved properties	$236,629	3,018	—	239,647
Unproved properties	69,288	4,580	—	73,868
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:				
Proved properties	$278,499	100,031	—	378,530
Unproved properties	43,171	14,281	—	57,452
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

(1) Includes amounts relating to estimated asset retirement obligations of $2.4 million, $16.3 million, and $14.1 million for assets placed in service in the years ended December 31, 2006, 2005, and 2004, respectively.

(2) Includes $37.2 million of capital expenditures related to offshore Gulf of Mexico operations from January 1, 2006 through the date of the Spin-off on March 2, 2006. Costs incurred related to offshore Gulf of Mexico operations for 2006 consist of $.7 million for property acquisitions, $24.0 million for exploration, and $12.5 million for development.

(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:

	2006	2005	2004
		(In Thousands)	
Costs related to proved properties	$ 4,751,171	5,957,805	5,201,562
Costs related to unproved properties	261,259	275,684	209,604
	5,012,430	6,233,489	5,411,166
Less accumulated depletion	(2,265,018)	(3,059,031)	(2,701,402)
	$ 2,747,412	3,174,458	2,709,764

(15) 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, 2006, 2005, and 2004 are presented below.

	United States	Canada	Total
		(In Thousands)	
2006			
Oil and gas sales	$636,897	177,572	814,469
Expenses:			
Production expense	174,648	41,143	215,791
Depletion expense	188,073	75,366	263,439
Accretion of asset retirement obligations	6,046	1,004	7,050
Income tax expense	103,498	17,970	121,468
Total expenses	472,265	135,483	607,748
Results of operations from producing activities	$164,632	42,089	206,721
Depletion rate per Mcfe	$ 2.09	2.42	2.17
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
Depletion rate per Mcfe	$ 2.17	2.40	2.21
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 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
Depletion rate per Mcfe	$ 2.05	1.93	2.03

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

(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 2006, 2005, and 2004 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 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.

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, 2004	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
Revisions of previous estimates	26,286	735	27,021	(83,435)	28,451	(54,984)	107,142
Extensions and discoveries	4,850	1,107	5,957	102,173	52,333	154,506	190,248
Production	(6,887)	(1,139)	(8,026)	(48,674)	(24,350)	(73,024)	(121,180)
Sales of reserves in place[(1)]	(13,047)	—	(13,047)	(248,028)	—	(248,028)	(326,310)
Purchases of reserves in place	3,889	—	3,889	114,886	—	114,886	138,220
Balance at December 31, 2006	107,169	5,695	112,864	580,096	197,943	778,039	1,455,223
Proved developed reserves at:							
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
December 31, 2006	73,239	5,041	78,280	407,965	158,174	566,139	1,035,819

(1) Includes 313 Bcfe related to the Spin-off on March 2, 2006, as discussed in Note 2.

(15) 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 37.5% in the U.S. and an average combined federal and provincial rate of 29.25% 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, 2006		
	United States	Canada	Total
		(In Thousands)	
Future oil and gas sales	$ 8,600,619	1,276,442	9,877,061
Future production costs	(2,349,072)	(287,054)	(2,636,126)
Future development costs	(681,060)	(87,555)	(768,615)
Future income taxes	(1,317,621)	(214,804)	(1,532,425)
Future net cash flows	4,252,866	687,029	4,939,895
10% annual discount for estimated timing of cash flows	(2,109,005)	(236,526)	(2,345,531)
Standardized measure of discounted future net cash flows	$ 2,143,861	450,503	2,594,364

	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

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

(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, 2006		
	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	$ 3,339,202	513,423	3,852,625
Changes resulting from:			
Sales of oil and gas, net of production costs	(507,337)	(136,429)	(643,766)
Net changes in prices and future production costs	(1,699,819)	(287,119)	(1,986,938)
Net changes in future development costs	(151,433)	(9,971)	(161,404)
Extensions, discoveries, and improved recovery	286,598	136,881	423,479
Development costs incurred during the period	311,883	51,729	363,612
Revisions of previous quantity estimates	304,238	84,013	388,251
Sales of reserves in place[1]	(1,380,077)	—	(1,380,077)
Purchases of reserves in place	371,265	—	371,265
Accretion of discount on reserves at beginning of year before income taxes	468,429	67,036	535,465
Net change in income taxes	800,912	30,940	831,852
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$ 2,143,861	450,503	2,594,364

[1] Includes the effect of the Spin-off on March 2, 2006, as discussed in Note 2.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2006 was based on weighted average year-end spot natural gas prices of approximately $5.28 per Mcf in the United States and approximately $5.05 per Mcf in Canada, and on weighted average year-end spot liquids prices of approximately $51.69 per barrel in the United States and approximately $48.76 per barrel in Canada.

	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
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

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

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 weighted average year-end spot natural gas prices of approximately $8.44 per Mcf in the United States and approximately $7.78 per Mcf in Canada, and on weighted average year-end spot liquids prices of approximately $54.03 per barrel in the Unites States 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
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 weighted average year-end spot natural gas prices of approximately $5.88 per Mcf in the United States and approximately $4.81 per Mcf in Canada, and on weighted average year-end spot liquids prices of approximately $39.23 per barrel in the United States and approximately $32.94 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, 2006 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, 2006. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by Ernst & Young 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 of Forest Oil Corporation

We have audited management's assessment, included in the accompanying Managements' Annual Report on Internal Control over Financial Reporting, that Forest Oil Corporation maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). 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, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Forest Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Forest Oil Corporation as of December 31, 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for the period ended December 31, 2006 and our report dated February 27, 2007 expressed an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
February 27, 2007

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

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, 2006 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 procedures for recommending nominees to the Board and Forest's Audit Committee and designated "audit committee financial expert" is set forth under the caption "Corporate Governance 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 "Executive Compensation—Director Compensation" in the Proxy Statement, which information is incorporated herein by reference. See also "Executive Compensation—Compensation Committee Report, and Corporate Governance Principles and Information About the Board and Its Committees—Compensation Committee Interlocks and Insider Participation" for additional information, 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, and Director Independence.

Information regarding certain relationships and related transactions is set forth under the caption "Transactions with Related Persons, Promoters and Certain Control Persons" and information regarding director independence is set forth under the caption "Corporate Governance Principles and Information about the Board and its Committees—Board Independence" included 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 and 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, 2006 and 2005
3. Consolidated Statements of Operations—Years Ended December 31, 2006, 2005, and 2004
4. Consolidated Statements of Shareholders' Equity—Years Ended December 31, 2006, 2005, and 2004
5. Consolidated Statements of Cash Flows—Years Ended December 31, 2006, 2005, and 2004
6. Notes to Consolidated Financial Statements—Years Ended December 31, 2006, 2005, and 2004

(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).
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).

Exhibit Number	Description
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 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).
4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	First Amendment to the 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 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).
4.10	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, incorporated herein by reference to Exhibit 4.11 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).

Exhibit Number	Description
4.11	Third Amendment to the Amended and Restated Combined Credit Agreements, effective as of October 31, 2006, among Forest Oil Corporation, Canadian Forest Oil Ltd., 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, 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, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2006 (File No. 001-13515).
4.12†	First Lien Credit Agreement dated as of December 8, 2006, among Forest Alaska Operating LLC, Forest Alaska Holding LLC, each of the lenders that is party thereto, Credit Suisse, as Administrative Agent and Collateral Agent, Credit Suisse Securities (USA) LLC and J.P. Morgan Securities Inc., as Co-Lead Arrangers and Joint Bookrunners, and JPMorgan Chase Bank, N.A., as Syndication Agent.
4.13†	Second Lien Credit Agreement dated as of December 8, 2006, among Forest Alaska Operating LLC, Forest Alaska Holding LLC, each of the lenders that is party thereto, Credit Suisse, as Administrative Agent and Collateral Agent, Credit Suisse Securities (USA) LLC and J.P. Morgan Securities Inc., as Co-Lead Arrangers and Joint Bookrunners, and JPMorgan Chase Bank, N.A., as Syndication 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, incorporated herein by reference to Exhibit 10.4 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
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, incorporated herein by reference to Exhibit 10.8 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
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).

Exhibit Number	Description
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, incorporated herein by reference to Exhibit 10.12 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.13*	Form of Grandfathered SVP Severance Agreement, incorporated herein by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2004 (File No. 001-13515).
10.14*	Form of SVP Severance Agreement, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2004 (File No. 001-13515).
10.15*	Form of VP Severance Agreement, incorporated herein by reference to Exhibit 10.5 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2004 (File No. 001-13515).
10.16*	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).
10.17*	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).
10.18*	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).
10.19*	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).
10.20*	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).
10.21*	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).
10.22*	Second Amendment to Forest Oil Corporation Pension Trust Agreement as Amended and Restated January 1, 2002, effective as of May 10, 2006, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2006 (File No. 001-13515).
10.23*	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).
10.24*	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 (File No. 001-13515).
10.25*	Forest Oil Corporation Amended and Restated 2005 Salary Deferred Compensation Plan, effective as of December 31, 2004, incorporated herein by reference to Exhibit 10.21 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).

Exhibit Number	Description
10.26*	First Amendment to the Forest Oil Corporation Amended and Restated Salary Deferral Compensation Plan, effective as of December 31, 2005, incorporated herein by reference to Exhibit 10.22 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.27*	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).
10.28*	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).
10.29*	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).
10.30*	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).
10.31*	Third Amendment to Forest Oil Corporation Executive Deferred Compensation Plan dated December 20, 2005, incorporated herein by reference to Exhibit 10.27 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).
10.32*†	Forest Oil Corporation Executive Deferred Compensation Plan as Amended and Restated, effective as of January 1, 2005.
10.33*	Forest Oil Corporation 2006 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 11, 2006 (File No. 001-13515).
10.34	Agreement and Plan of Merger by and among Forest Oil Corporation, MJCO Corporation and The Houston Exploration Company dated as of January 7, 2007, incorporated herein by reference to Exhibit 2.1 to Form 8-K for Forest Oil Corporation dated January 7, 2007 (File No. 001-13515).
10.35	Voting Agreement dated as of January 8, 2007, by and among Forest Oil Corporation, MJCO Corporation and JANA Master Fund, Ltd., and JANA Piranha Master Fund, Ltd., incorporated herein by reference to Exhibit 2.2 to Form 8-K for Forest Oil Corporation dated January 7, 2007 (File No. 001-13515).
10.36	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).
10.37	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).
10.38	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).
10.39	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).

Exhibit Number	Description
10.40	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 Ernst & Young LLP.
23.2†	Consent of KPMG LLP.
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: February 28, 2007

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, 2006, 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)	February 28, 2007
/s/ DAVID H. KEYTE David H. Keyte	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2007
/s/ VICTOR A. WIND Victor A. Wind	Corporate Controller (Principal Accounting Officer)	February 28, 2007
/s/ FORREST E. HOGLUND Forrest E. Hoglund	Chairman of the Board of Directors	February 28, 2007
/s/ WILLIAM L. BRITTON William L. Britton	Director	February 28, 2007
/s/ LOREN K. CARROLL Loren K. Carroll	Director	February 28, 2007
/s/ CORTLANDT S. DIETLER Cortlandt S. Dietler	Director	February 28, 2007
/s/ DOD. A. FRASER Dod. A. Fraser	Director	February 28, 2007
/s/ JAMES H. LEE James H. Lee	Director	February 28, 2007
/s/ JAMES D. LIGHTNER James D. Lightner	Director	February 28, 2007
/s/ PATRICK R. MCDONALD Patrick R. McDonald	Director	February 28, 2007

Index to Exhibits

Exhibit Number	Description
4.12	First Lien Credit Agreement dated as of December 8, 2006, among Forest Alaska Operating LLC, Forest Alaska Holding LLC, each of the lenders that is party thereto, Credit Suisse, as Administrative Agent and Collateral Agent, Credit Suisse Securities (USA) LLC and J.P. Morgan Securities Inc., as Co-Lead Arrangers and Joint Bookrunners, and JPMorgan Chase Bank, N.A., as Syndication Agent.
4.13	Second Lien Credit Agreement dated as of December 8, 2006, among Forest Alaska Operating LLC, Forest Alaska Holding LLC, each of the lenders that is party thereto, Credit Suisse, as Administrative Agent and Collateral Agent, Credit Suisse Securities (USA) LLC and J.P. Morgan Securities Inc., as Co-Lead Arrangers and Joint Bookrunners, and JPMorgan Chase Bank, N.A., as Syndication Agent.
10.32	Forest Oil Corporation Executive Deferred Compensation Plan as Amended and Restated, effective as of January 1, 2005.
21.1	List of Subsidiaries of Registrant.
23.1	Consent of Ernst & Young LLP.
23.2	Consent of KPMG LLP.
23.3	Consent of DeGolyer and MacNaughton.
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.

* Furnished herewith.

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

INDEPENDENT AUDITORS

Ernst & Young LLP
370 Seventeenth Street, Suite 3300
Denver, Colorado 80202
720.931.4000

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
888.213.0882

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
707 Seventeenth Street, Suite 3010
Denver, Colorado 80202
Thursday, May 10, 2007 at 9:00 a.m. MT

CERTIFICATIONS

The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to our Form 10-K. Forest has also submitted to the New York Stock Exchange a certificate of the Chief Executive Officer certifying that he is not aware of any violations by Forest of the NYSE corporate governance listing standards.

In this Annual Report, when we refer to "Remainco", we mean the portion of Forest not included in the March 2, 2006 spin-off of our Gulf of Mexico operations and subsequent merger of those operations with a subsidiary of Mariner Energy, Inc.

EXPLANATION OF RESERVE REPLACEMENT RATIO AND FD&A COSTS

All-Sources Reserve Replacement Ratio

Forest Remainco's all-sources reserve replacement ratio of 372% was calculated by dividing the sum of total additions, 420 Bcfe, by 2006 net sales volumes of 113 Bcfe.

FD&A Costs

Forest Remainco's FD&A costs of $2.15 per Mcfe were calculated by dividing the sum of total exploration, development and acquisition costs, $904 million, by the sum total additions to estimated proved oil and gas reserves during 2006 of 420 Bcfe.

Organic Reserve Replacement Ratio

Forest Remainco's organic reserve replacement ratio of 258% was calculated by dividing the sum of total additions to estimated proved oil and gas reserves during 2006, excluding purchases of properties, 282 Bcfe, by estimated 2006 net sales volumes of 109.5 Bcfe, which excludes the 13 MMcfe/d of net sales volume attributable to the Cotton Valley acquisition that closed on March 31, 2006.

Organic F&D Costs

Forest Remainco's organic F&D costs of $2.09 per Mcfe were calculated by dividing the sum of total exploration and development costs, $589 million, by the sum of total additions to estimated proved oil and gas reserves during 2006, excluding purchases of properties, of 282 Bcfe.

FORWARD-LOOKING STATEMENTS

This report included forward-looking statements, including those related to oil and gas reserve estimates, 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" and Item 1A, header "Estimates of oil and gas reserves are uncertain and inherently imprecise," in Forest's 2006 10-K for additional disclosures.

END

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