IN THE ZONE

ANNUAL REPORT 2007

Dear Fellow Shareholders

2007 HIGHLIGHTS

- ***Acquired The Houston Exploration Company; with asset additions to the Eastern, Southern and Western Business Units***
- ***Sold Forest Oil's Alaska assets***
- ***Record estimated proved reserves of more than 2.1 Tcfe***
- ***Record adjusted earnings of $223 million***
- ***Record adjusted EBITDA of $871 million***
- ***Record adjusted discretionary cash flow of $742 million***
- ***Reduced total cash costs in the fourth quarter of 2007 to $2.32/Mcfe***
- ***Replaced 703% of production at an all-sources finding cost of $2.27/Mcfe; organic finding costs were even lower at $2.21/Mcfe***
- ***Recapitalized the Company subsequent to the close of the Houston Exploration acquisition***
- ***Two successful wells in Italy resulted in first estimated proved reserves outside of North America***

The end of 2007 marks another record year for Forest Oil. Most importantly, our share price performance reflected a 56 percent increase, near the top of our peer group and a 17-year high for our company. In fact, the themes of our recent annual reports illustrate this rapid transformation to the portfolio of assets we desired a few years back. In 2004, our theme was "Our People, Our Strength" as the new management team launched its Four Point Strategy. In 2005, the theme "Improved Focus" described the streamlining of the Company's asset base and cost structure. In 2006, "Taking the Next Step" reflected a series of major transactions to shift the Company from an offshore producer to an onshore North America exploitation company. And now, in 2007, we are "In the Zone" as Forest Oil enjoys the results of the "sweet spot" in the portfolio we have created, with its enviable cost efficiencies and similar geologic characteristics.

OUR RESULTS

During 2007, we set all-time records for estimated proved reserves and adjusted earnings, EBITDA and discretionary cash flow while growing production by 28 percent. We also reduced our cost structure to one of the lowest in our industry. These highlights are summarized on the left hand side of this page. We did exactly what we said we would do. Reaching over 2 Tcfe in estimated proved reserves for the first time in the history of this company is even more impressive when we consider the recent sales of $1.8 billion in assets to complete our exit from the Gulf of Mexico and Alaska. Despite those sales, we grew the Company both overall and organically while approximately spending our internally generated cash flow.

OUR TRANSFORMATION

The speed of Forest Oil's transformation has been remarkable. The utilization of innovative transactions has played a pivotal role. Virtually *all* of the assets we inherited in 2003 are gone, resulting in a "new" company with the upside in front of us, operated by an energized and talented team of employees. Our people have been transformed as well, starting with their empowerment and alignment with shareholders. Our team has never been complacent, always taking quick action ahead of industry trends.

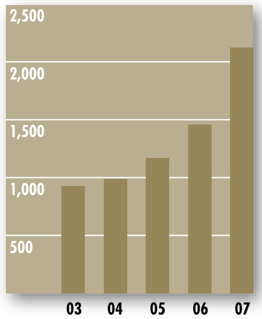
OUR TRANSACTIONS

During our transformation, we acquired more than $3.7 billion in assets while making complete exits from the Gulf of Mexico, Alaska and ten foreign countries. We chose to buy in North America where our exploitation and cost cutting expertise would prove the most beneficial. This "fork in the road" for Forest Oil coincided with the industry shift to resource plays and less

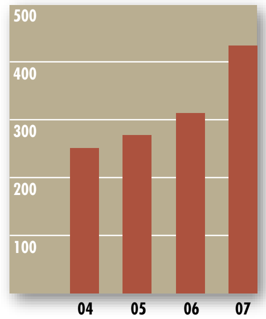
Forrest E. Hoglund Chairman of the Board

H. Craig Clark President and CEO

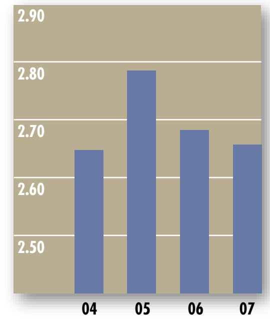
Estimated Proved Reserves* *(Bcfe)*



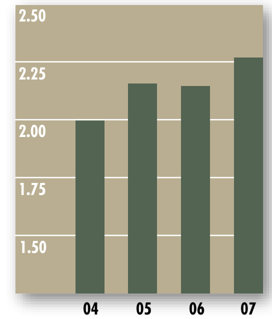
Production* *(MMcfe/d)*



Total Cash Costs* *($ per Mcfe)*



Total FD&A Costs* *($ per Mcfe)*



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

conventional reservoir targets. A case in point is our entry into East Texas, followed by the current horizontal drilling phenomenon. We purchased assets in the exact areas we targeted while showing discipline on our acquisition metrics. Innovation was involved in most of the transactions, notably the tax-free nature of the Gulf of Mexico spin-off and the $1 billion special dividend to our shareholders. Other innovative transactions include the Alaska term loan financing, the sale lease-back transaction associated with our drilling rigs and several wholesale capital expenditure re-allocations. All of these acquisitions, including the recent Houston Exploration acquisition, are well on the way to becoming successes, as most of these have already paid out. The upside created now belongs to the Forest Oil shareholders.

OUR PORTFOLIO

Our new portfolio, focused primarily in onshore North America, is concentrated in five producing basins. By design, the portfolio is proportionately balanced in terms of production, reserves, cash flow, capital spending and acreage. This even distribution will prevent a single asset from controlling our future or determining our overall results. Embedded in each of the four producing business units are legacy assets that provide more than 5,000 unbooked future projects containing more than 2.8 Tcfe of low-risk drilling opportunities. Our confidence regarding their potential is high. These opportunities lie within different geographic areas but within similar types of geologic zones, which makes them low risk. In addition to a large project inventory, each area has a sizeable acreage position. In 2007 alone, we added more than 800,000 undeveloped acres in our focus areas.

OUR FUTURE

Our future lies in the current portfolio, with execution and more growth planned for those areas. The 2007 metrics speak for the asset quality; the finding costs, operating costs, G & A costs, production and estimated proved reserve additions illustrate the quality of this relatively new portfolio. Exploitation and the use of new technology have only just begun. Our efficiencies and new technology are the main reasons we chose to own these types of assets several years ago. We intend to add value in many ways, including the drillbit, acquisitions, divestitures, marketing and new technology — in other words, all of the above. We plan to further upgrade our asset base with strategic asset divestitures while increasing our activity in major areas like the Texas Panhandle, Ark-La-Tex, Canadian Deep Basin and South Texas. Our spending discipline on capital projects and acquisitions will remain consistent and will account for steady growth while providing the excellent finding cost metrics we have achieved over the past several years. Discipline may well be the hallmark of this Company, discipline to stay “In the Zone.”

OUR THANKS

At the upcoming annual shareholder meeting in May, Mr. Forrest Hoglund will retire from our Board of Directors and step down as our non-executive Chairman. Forrest was the catalyst for change in 2003. Under his direction, the transformation of Forest Oil was begun. His reputation in our industry and on Wall Street is impeccable. Mr. Jim Lightner will succeed Forrest as non-executive Chairman. Like Forrest, Jim has a long record of creating shareholder value as Chairman of Tom Brown, Inc. and as a Forest Oil board member. Thank you, Mr. Hoglund, for all you have done for Forest Oil.

FORREST E. HOGLUND
Chairman of the Board

H. CRAIG CLARK
President and CEO

Operations

In 2007, Forest announced and closed the largest acquisition in its history, which was integrated quickly and efficiently. Further, a significant amount of non-strategic assets, including its Alaska properties, were divested. These actions, coupled with the expansion of the "Big 5" areas into offset acreage, have resulted in further repositioning the Company for future growth within its "Big 5" assets. This demonstrates that Forest is "In the Zone" in its acquisition, exploitation and organic development strategies. The "Big 5" assets now include the Greater Buffalo Wallow Area in the Texas Panhandle; the Deep Basin of Alberta in Canada; the newly expanded Cotton Valley Play in East Texas; the newly acquired Arkoma Basin assets in Western Arkansas; and the newly acquired fields in South Texas. While being geographically diverse, each of these plays has similar geology. As displayed on the well logs to the right, they all have multiple, tight gas sand zones that must be fracture stimulated in multiple stages. The plays are at the same approximate depth and the commonality of fracture techniques and production methodology allows us to focus on cost efficiency. Simply stated, "different geography, similar geology, same focus on operational excellence."

GREATER BUFFALO WALLOW AREA

4Q 2007 Net Production Exit Rate (MMcfe/d)	49
4Q 2008 Anticipated Net Production Exit Rate (MMcfe/d)	60-65
4Q 2006 – 4Q 2007 Production Growth (%)	23
Total number of locations (including PUDs)	917
Total locations to drill in 2008	65-75

2007 marked a very important year for the Greater Buffalo Wallow Area with a successful step-out effort into offset acreage southeast of the legacy acreage, with initial production rates as high as 8.0 MMcfe/d. At year-end the offset acreage totaled approximately 40,300 gross acres out of a total Greater Buffalo Wallow Area of approximately 50,300 gross acres. Forest will utilize six rigs in the Greater Buffalo Wallow Area in 2008 and expects to drill approximately 70 wells. Forest will continue its highly economical exploitation efforts, using multiple slick-water fracture technology and an aggressive marketing plan throughout the play. From this, Forest expects to exit 2008 with net production between 60 and 65 MMcfe/d.

CANADIAN DEEP BASIN

4Q 2007 Net Production Exit Rate (MMcfe/d)	38
4Q 2008 Anticipated Net Production Exit Rate (MMcfe/d)	40-45
4Q 2006 – 4Q 2007 Production Growth (%)	3
Total number of locations (including PUDs)	155
Total locations to drill in 2008	30-40

With the Wild River Field reaching its maturity in the next few years, Canadian Forest will see a shift in focus to Sundance/Ansell and to

Hinton in 2008, just southeast of Wild River. Sundance/Ansell shares the same geologic pay horizons as the Wild River Field, allowing Forest to benefit from its three and a half year successful drilling program where the Company has seen net production rates increase from 9 MMcfe/d to 38 MMcfe/d, an increase of over 300%. The Sundance/Ansell wells are multi-layer fracture stimulated completions with production commingled in the same method that made the Wild River Field so successful. With 120 potential wells to drill in these offset locations at Sundance/Ansell, Forest has plenty of running room to expand the Cretaceous play while, at the same time, further developing the Wild River Field's uphole, behind pipe potential through recompletion opportunities. From this, Forest expects to exit 2008 with production between 40 and 45 MMcfe/d. Efforts on production cost reductions will increase as the play was the most recent recipient of Forest's successful "Project FOCUS" cost cutting program.

COTTON VALLEY

4Q 2007 Net Production Exit Rate (MMcfe/d)	53
4Q 2008 Anticipated Net Production Exit Rate (MMcfe/d)	57–62
4Q 2006 – 4Q 2007 Production Growth (%)	152
Total number of locations (including PUDs)	594
Total locations to drill in 2008	50-60

Horizontal wells in the Cotton Valley Trend were the 'play of the day' in East Texas in 2007. With 30,400 gross acres (total of 74,400 gross acres at December 31, 2007) bolted on to Forest's existing position through the Houston Exploration acquisition, Forest significantly increased the size of its footprint to drill both horizontal and vertical wells, using the same hybrid fracture technology that is utilized throughout its tight gas sand portfolio, while commingling production to optimize rates of return. Forest has been highly successful drilling horizontally, and thus will run two horizontal rigs in 2008 utilizing this application. Forest is anticipating to drill 10 to 12 horizontal wells on large undeveloped acreage blocks and 40 vertical wells in tighter spaced areas that have historically yielded highly economic wells. From this, Forest expects to exit 2008 with net production of approximately 60 MMcfe/d.

ARKOMA

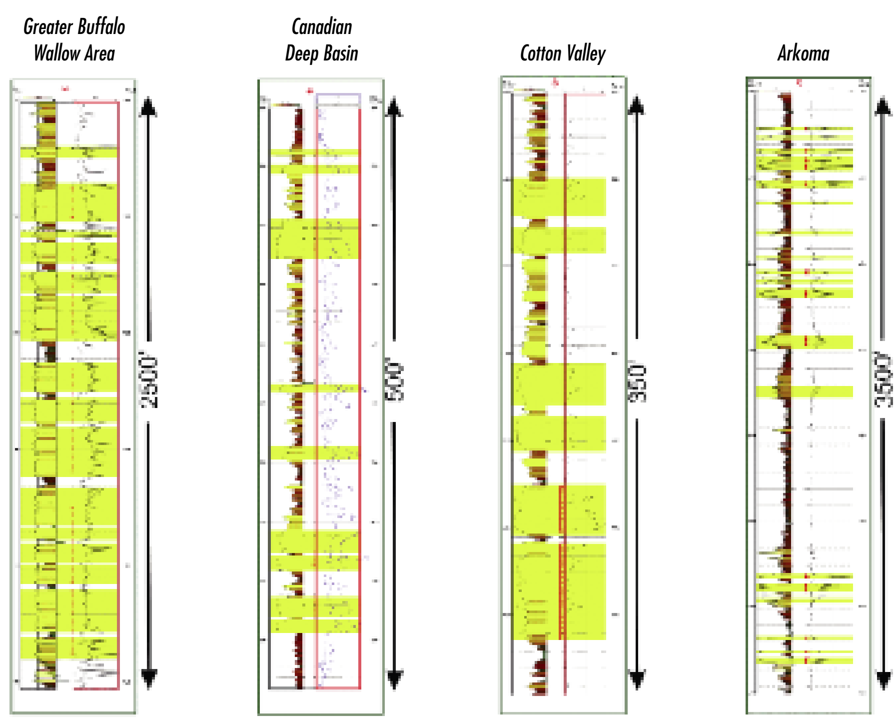
4Q 2007 Production Exit Rate (MMcfe/d)	41
4Q 2008 Anticipated Production Exit Rate (MMcfe/d)	40–45
Total number of locations (including PUDs)	481
Total locations to drill in 2008	95-100

The conventional Arkoma play in Western Arkansas has been another great addition from the Houston Exploration acquisition. With low well costs and faster drilling times due to the use of air drilling and extremely low operating costs, this play yields attractive rates of return. Forest expects net production to increase by 5% in 2008, with a fourth quarter exit rate of 43 MMcfe/d, while generating significant cash flow from the asset. Further, the play lends itself favorably to multiple stage recompletion programs and possible horizontal exploitation that Forest excels at in other areas.

SOUTH TEXAS

4Q 2007 Net Production Exit Rate (MMcfe/d)	122
4Q 2008 Anticipated Net Production Exit Rate (MMcfe/d)	129
Total number of locations (including PUDs)	405
Total locations to drill in 2008	50-55

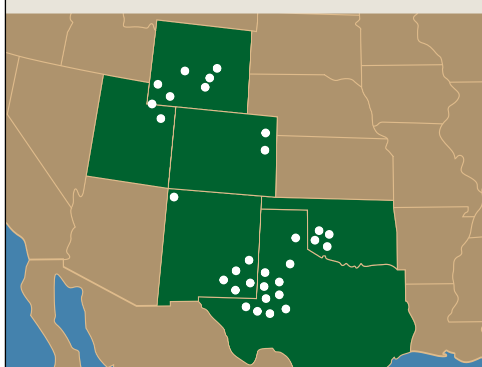
The South Texas assets are significant cash flow generators due to high rate production from the Wilcox and Vicksburg trends. The assets obtained from the Houston Exploration acquisition fit very well with Forest's legacy assets such as McAllen Ranch (Vicksburg) and the Katy Field (Wilcox). The significant acreage and production acquired in 2007 yielded critical mass for South Texas. While drilling activity was reduced in the second half of 2007 to allow for prospect refinement, a large acreage position combined with an extensive 3-D seismic inventory will provide for an expanded drilling program in 2008. Five rigs are currently being utilized with a planned program of 52 wells.



Operational Fact Sheet

Western

	2007	2006	2005
NET PRODUCTION			
Gas (MMcf/d)	77.4	71.0	58.7
Liquids (MBbls/d)	10.7	10.2	9.4
ESTIMATED PROVED RESERVES			
Gas (Bcf)	408.7	339.0	367.1
Liquids (MMBbls)	59.9	60.9	52.3
Equivalent (Bcfe)	767.9	704.1	680.9
DEVELOPED ACREAGE			
Gross	353,754	262,461	274,881
Net	217,814	154,267	157,556
UNDEVELOPED ACREAGE			
Gross	1,128,547	207,190	197,206
Net	789,494	103,820	97,678
GROSS WELL COUNT			
Gas	3,663	3,091	3,655
Oil	2,251	2,674	2,661
CAPITAL EXPENDITURES In thousands			
	$278,701	$299,398	$492,123



2007 HIGHLIGHTS

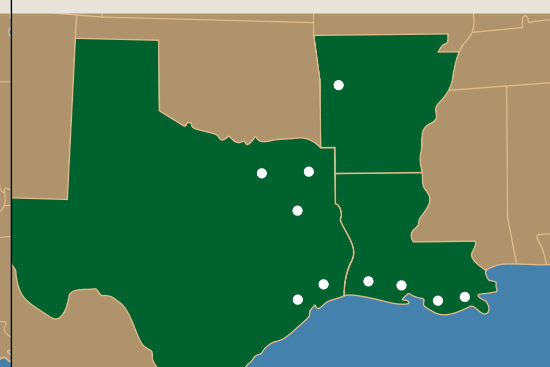
- Increased estimated proved reserves 9% to 768 Bcfe at an all-sources reserve replacement ratio of 306%
- Increased net production 7% to 141 MMcfe/d in 2007 from 132 MMcfe/d in 2006
- Record net production of 49 MMcfe/d in the Greater Buffalo Wallow Area in the fourth quarter of 2007
- 100% success rate in the Greater Buffalo Wallow Area with initial net production rates as high as 8.0 MMcfe/d due to continued improvement with the utilization of slick-water fracture technology and deeper pay completions
- Added 4,900 acres in the Greater Buffalo Wallow Area increasing total gross acreage to 50,300 acres
- Drilled 24 wells in the Midland Basin at a 100% success rate and an additional 23 wells were successfully recompleted in the same area

FUTURE STRATEGY

- 2008 drilling program calls for 250 wells and a continued high pace of additional projects
- Drill 70 wells in 2008 in the Greater Buffalo Wallow Area with a total of 917 potential Granite Wash/Atoka locations identified on 20 and 40 acre spacing
- Process and interpret seismic related to the Greater Vermejo/Haley Area in 2008 while using a one rig program
- Drill 20 wells in 2008 in the Uinta Basin including tests to evaluate the Deep Mesaverde, Mancos, and Dakota objectives
- Increase activity in 2008 in the Midland Basin with a total of 780 potential locations identified

Eastern

	2007	2006	2005
NET PRODUCTION			
Gas (MMcf/d)	66.0	36.2	27.7
Liquids (MBbls/d)	4.1	3.0	2.7
ESTIMATED PROVED RESERVES			
Gas (Bcf)	470.7	232.4	125.2
Liquids (MMBbls)	21.6	17.6	10.1
Equivalent (Bcfe)	600.3	338.1	185.8
DEVELOPED ACREAGE			
Gross	172,633	184,475	101,554
Net	113,557	102,385	59,118
UNDEVELOPED ACREAGE			
Gross	282,298	252,482	259,310
Net	139,101	124,252	122,583
GROSS WELL COUNT			
Gas	898	441	344
Oil	350	345	165
CAPITAL EXPENDITURES In thousands			
	$227,587	$412,803	$39,645



2007 HIGHLIGHTS

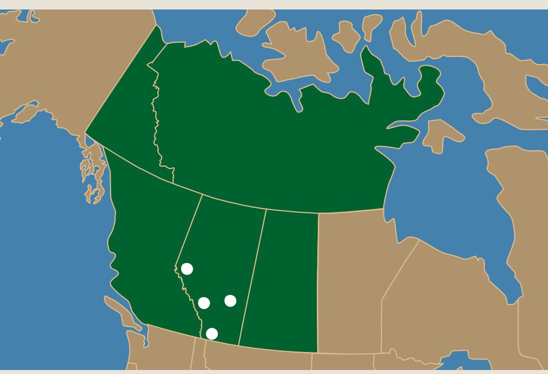
- Increased estimated proved reserves 151% to 600 Bcfe at an all-sources reserve replacement ratio of 1,160%
- Increased net production 40% to a record 90 MMcfe/d in 2007 from 54 MMcfe/d in 2006
- Record net production of 53 MMcfe/d in the East Texas Cotton Valley Play in the fourth quarter of 2007
- 100% success rate in the East Texas Cotton Valley Play with initial net production rates as high as 7.8 MMcfe/d through the utilization of horizontal drilling on large undeveloped acreage blocks
- Added 30,400 gross acres in the East Texas Cotton Valley Play increasing total gross acreage to 74,400 acres
- Added conventional Arkoma Basin assets in Western Arkansas that utilize similar tight gas sand completion techniques that are found in Forest's largest assets
- Drilled seven wells in 2007 in Forest's Barnett Shale Play, all in Hill County at a 100% success rate
- Increased size and scope of Forest's Barnett Shale Play, increasing total acreage to over 70,000 gross acres and added acreage in Erath County through a farm-in agreement

FUTURE STRATEGY

- 2008 drilling program calls for 178 wells and a continued high pace of additional projects
- Drill 50 wells in 2008 in the East Texas Cotton Valley Play with a total of 594 potential locations identified
- Drill 100 wells in 2008 in the conventional Arkoma Basin with a total of 481 potential locations identified

Canada

	2007	2006	2005
NET PRODUCTION			
Gas (MMcf/d)	68.7	66.7	51.8
Liquids (MBbls/d)	2.9	3.1	3.4
ESTIMATED PROVED RESERVES			
Gas (Bcf)	208.2	197.9	141.5
Liquids (MMBbls)	7.3	5.7	5.0
Equivalent (Bcfe)	252.1	232.1	171.5
DEVELOPED ACREAGE			
Gross	286,016	267,157	236,678
Net	157,737	151,645	136,837
UNDEVELOPED ACREAGE			
Gross	852,704	1,082,504	1,118,462
Net	375,398	581,746	598,481
GROSS WELL COUNT			
Gas	626	572	515
Oil	341	329	323
CAPITAL EXPENDITURES In thousands			
	$173,212	$150,955	$115,019



2007 HIGHLIGHTS

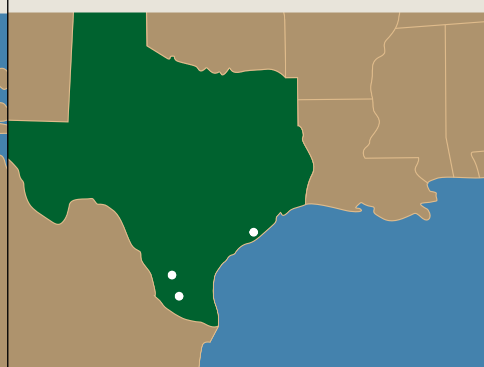
- Increased estimated proved reserves 9% to 252 Bcfe at an all-sources reserve replacement ratio of 211%
- Increased net production 1% to 86 MMcfe/d in 2007 from 85 MMcfe/d in 2006
- Net production of 38 MMcfe/d in the Deep Basin in the fourth quarter of 2007
- 100% success rate in the Deep Basin with initial net production rates as high as 6.0 MMcfe/d through the utilization of slick water fracture technology
- Added 7,040 gross acres in the Deep Basin increasing total gross acreage to 73,000 acres

FUTURE STRATEGY

- 2008 drilling program calls for 62 wells and a continued high pace of additional projects
- Drill 35 wells in 2008 in the Deep Basin with a total of 155 potential locations identified
- Increase activity at Sundance/Ansell as the Wild River Field play moves south and east
- Test recompletion opportunities uphole in the Wild River Field with possible horizontal drilling activity
- Continue development at Hinton
- Continue reactivation activity at Hayter during 2008 after salt water disposal capacity is increased
- Drill approximately 13 wells in 2008 at Evi with two of the wells being drilled and completed horizontally

Southern

	2007	2006	2005
NET PRODUCTION			
Gas (MMcf/d)	80.3	N/A	N/A
Liquids (MBbls/d)	1.6	N/A	N/A
ESTIMATED PROVED RESERVES			
Gas (Bcf)	408.5	N/A	N/A
Liquids (MMBbls)	5.7	N/A	N/A
Equivalent (Bcfe)	442.6	N/A	N/A
DEVELOPED ACREAGE			
Gross	192,752	N/A	N/A
Net	135,852	N/A	N/A
UNDEVELOPED ACREAGE			
Gross	73,843	N/A	N/A
Net	34,208	N/A	N/A
GROSS WELL COUNT			
Gas	1,429	N/A	N/A
Oil	23	N/A	N/A
CAPITAL EXPENDITURES In thousands			
	$103,614	N/A	N/A



2007 HIGHLIGHTS

- Estimated proved reserves of 443 Bcfe
- Averaged 90 MMcfe/d in 2007 in this newly created Business Unit as a result of the acquisition of the Houston Exploration Company
- 87% success rate in the Charco and Rincon Fields with initial net production rates as high as 9.0 MMcfe/d
- Katy production increased 100% in 2007 with gross production reaching 28 MMcfe/d
- South Texas gross acreage position at 190,000 acres

FUTURE STRATEGY

- 2008 drilling program calls for 59 wells and a continued high pace of additional projects
- Drill 52 wells in 2008 in the Charco, Rincon and McAllen Ranch Fields
- Exploratory drilling is planned in areas near Charco and Rincon for deeper objectives utilizing 3-D seismic
- Drill five wells in 2008 in Katy in the Wilcox formation

International

	2007	2006	2005
NET PRODUCTION			
Gas (MMcf/d)	–	–	–
Liquids (MBbls/d)	–	–	–
ESTIMATED PROVED RESERVES			
Gas (Bcf)	56.3	–	–
Liquids (MMBbls)	–	–	–
Equivalent (Bcfe)	56.3	–	–
DEVELOPED ACREAGE			
Gross	2,500	–	–
Net	2,250	–	–
UNDEVELOPED ACREAGE			
Gross	5,469,514	5,835,867	5,937,828
Net	2,967,091	3,333,194	3,194,227
GROSS WELL COUNT			
Gas	2	–	–
Oil	–	–	–
CAPITAL EXPENDITURES In thousands			
	$15,853	$6,984	$3,688

2007 HIGHLIGHTS

- Booked estimated proved reserves of 56 Bcfe in Italy
- Drilled two wells during the year at Monte Pallano, which tested at a combined 22 MMcfe/d rate without fracture stimulation
- Successfully divested Australian assets for $7 million that had no associated estimated proved reserves or production

FUTURE STRATEGY

- Capital spending in 2008 is planned for the pipeline and facilities at the Monte Pallano discovery in onshore central Italy, with first sales expected in 2009
- Additional exploratory drilling in the Po Valley, Northern Italy in 2008
- Continue progress in securing Ibhubesi Production Right and associated gas contracts in South Africa

Executive Officers

H. CRAIG CLARK, 51
President and
Chief Executive Officer
Years of Service: 7

DAVID H. KEYTE, 51
Executive Vice President
and Chief Financial Officer
Years of Service: 20

JOHN C. RIDENS, 52
Executive Vice President
and Chief Operating Officer
Years of Service: 4

CECIL N. COLWELL, 57
Senior Vice President,
Worldwide Drilling
Years of Service: 19

LEONARD C. GURULE, 51
Senior Vice President
Years of Service: 5

CYRUS D. MARTER IV, 44
Senior Vice President,
General Counsel and Secretary
Years of Service: 6

GLEN J. MIZENKO, 45
Senior Vice President, Business
Development and Engineering
Years of Service: 7

MARK E. BUSH, 48
Vice President, Eastern Region
Years of Service: 10

STEPHEN T. HARPHAM, 46
Vice President, Western Region
Years of Service: 6

RONALD C. NUTT, 50
Vice President, Southern Region
Years of Service: 1

VICTOR A. WIND, 34
Corporate Controller
Years of Service: 3

Board of Directors

WILLIAM L. BRITTON, age 73, 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 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. and Chairman of Hanzell Vineyards, Ltd. and Gearg-Market Investment Company of California. He is a director of Barking Power Limited, Akita Drilling Ltd. and The Denver Broncos Football Club. He is a member of our Nominating and Corporate Governance Committee.

LOREN K. CARROLL, age 64, has been a director since November 2006. Mr. Carroll served as President and Chief Executive Officer of M-I SWACO, a supplier of drilling and completion fluids and waste management products and services company owned 60% 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 from March 1994 until his retirement in April 2006. He initially joined Smith International in December 1984 and was serving as Executive Vice President and Chief Financial Officer when he left in 1989 and returned in 1992. Mr. Carroll is a director of Smith International, Inc., Fleetwood Enterprises, Inc., a producer of recreational vehicles and manufactured homes, CGG-Veritas, a geophysical services and equipment company and KBR, Inc., an engineering and construction company. Mr. Carroll is a member of our Compensation Committee and is the Chairman of the Nominating and Corporate Governance Committee.

DOD A. FRASER, age 57, 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 is the Chairman of our Audit Committee and is a member of our Nominating and Corporate Governance Committee.

FORREST E. HOGLUND, age 74, 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. 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. He has announced that he will retire as a Forest director in May 2008.

JAMES H. LEE, age 59, 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 55, has been a director since 2004. Mr. Lightner has been a Partner and Chief Executive Officer of Orion Energy Partners, an oil and gas exploration and production company, since its inception in August 2004. 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. Effective at the 2008 Annual Meeting, the Board has elected Mr. Lightner to serve as the non-executive Chairman of the Board.

PATRICK R. MCDONALD, age 50, 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. Prior to 1998, 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 51, 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, 2007

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, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer", "accelerated filer", and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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 29, 2007, the last business day of the registrant's most recently completed second fiscal quarter, was $3,357,673,088 (based on the closing price of such stock on the New York Stock Exchange Composite Tape).

There were 88,407,646 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 15, 2008.

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, 2007 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 currently conduct our operations in three geographical segments and five business units. Geographical segments include: the United States, Canada, and International. Business units include: Western, Eastern, Southern, Canada, and International. We conduct exploration and development activities in each of our geographical segments; however, substantially all of our estimated proved reserves and all of our producing properties are located in North America. Forest's total estimated proved reserves as of December 31, 2007 were approximately 2.1 Tcfe. At December 31, 2007, approximately 85% of our estimated proved oil and gas reserves were in the United States, approximately 12% were in Canada, and approximately 3% were in Italy. See Note 14 to the Consolidated Financial Statements for additional information about our geographical segments.

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.

Over the last several years, we have implemented a strategy directed at transforming Forest from a predominantly Gulf of Mexico oil and gas producer with frontier exploration emphasis to a North American onshore producer with numerous low risk opportunities for growth. As part of this transformation, we have made several key acquisitions and dispositions, including most recently the acquisition of The Houston Exploration Company ("Houston Exploration") in June 2007, the sale of our Alaska operations in August 2007, and the disposition of our offshore Gulf of Mexico properties in March 2006.

Acquisition of Houston Exploration

On June 6, 2007, Forest completed the acquisition of Houston Exploration in a cash and stock transaction totaling approximately $1.5 billion and the assumption of Houston Exploration's debt. Houston Exploration was an independent natural gas and oil producer engaged in the exploration, development, exploitation, and acquisition of natural gas and oil reserves in North America. Houston Exploration had operations in four producing regions within the United States: South Texas, East Texas, the Arkoma Basin of Arkansas, and the Uinta and DJ Basins in the Rocky Mountains. At the time of the acquisition in June 2007, Forest estimated the Houston Exploration oil and gas reserves to be 653 Bcfe, of which 71% were classified as proved developed and the remaining amounts were classified as proved undeveloped. Pursuant to the terms and conditions of the agreement and plan of merger ("Merger Agreement"), Forest paid total merger consideration of $750 million in cash and issued approximately 24 million common shares, valued at $30.28 per share. The per share value of the Forest common shares issued was calculated as the average of Forest's closing share price for a five day period surrounding the announcement date of the acquisition on January 7, 2007. The cash component of the merger consideration was financed from a private placement of $750 million of 7¼% senior notes due 2019 and borrowings under our $1.0 billion second amended and restated credit facilities that were executed on June 6, 2007.

Sale of Alaska Assets

On August 27, 2007, Forest sold all of its assets located in Alaska (the "Alaska Assets") to Pacific Energy Resources Ltd. ("PERL"). Forest estimated the proved oil and gas reserves associated with the Alaska Assets at closing to be 173 Bcfe. The total consideration received for the Alaska Assets included $400 million in cash, 10 million shares of PERL common stock (subject to certain restrictions), and a zero coupon senior subordinated note from PERL due 2014 in the principal amount at stated maturity of $60.8 million.

Spin-off of Offshore Gulf of Mexico Operations

On March 2, 2006, Forest completed the spin-off of its offshore Gulf of Mexico operations by means of a special 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 approximately 50.6 million 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. Forest estimated the proved oil and gas reserves associated with the Spin-off to be 313 Bcfe.

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 the associated liability were included in the Spin-off. Subsequent to the closing, in 2006 Forest received additional net cash proceeds of $21.7 million from MERI for a total of $197.8 million. In accordance with the transaction agreements, Forest and MERI each submitted post-closing adjustments, from which Forest paid MERI a total of $5.8 million during 2007. Additional adjustments to the cash amount may occur during 2008 pending the resolution of certain accounting matters that are the subject of ongoing arbitration between Forest and MERI. The arbitration is currently expected to be concluded in the second half of 2008.

Business Strategy

We adopted a new business strategy in 2003 that includes four key points: make strategic acquisitions, increase production organically, control costs, and remain financially flexible.

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 strategy in 2003, through 2007 we have incurred approximately $3.7 billion (including deferred tax gross ups of $.7 billion recorded in connection with business combinations) to acquire oil and gas assets including approximately 1.5 Tcfe of estimated proved reserves, over 1.5 million net acres, drilling rigs, and transportation infrastructure. In general, our acquisition program has focused on acquisitions of properties that have substantial development drilling opportunities and undeveloped acreage.

During 2007, we made approximately $2.2 billion of oil and gas acquisitions (including approximately $559 million of deferred tax gross ups), including the acquisition of Houston Exploration in June 2007 as discussed above. The oil and gas properties of Houston Exploration included approximately 926,000 net acres, an estimated 653 Bcfe of estimated proved reserves, and production of 204 MMcfe per day. Of the 926,000 net acres, approximately 738,000 net acres were undeveloped.

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.

Organic Growth

Our acquisition program has provided oil and gas properties conducive to low-risk, repeatable development and exploitation opportunities focused primarily in unconventional tight gas sand reservoirs. In 2008, Forest expects continued organic growth from its planned exploitation activities, including exploration and development drilling, workovers, stimulation treatments, enhanced oil recoveries, and recompletions.

Focus on Cost Control

Maintaining capital spending discipline and a focus on cost control are keystones of Forest's business philosophy. A critical area of our cost control efforts is lease operating expenses. While in a period of rising costs in the oil and gas sector, we decreased our per-unit lease operating expenses from the level achieved in 2005. See "*Lease Operating Expenses*" and the accompanying table in Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations." Lease operating expenses decreased 11% to $1.08 per Mcfe in 2007 compared to $1.21 per Mcfe in 2005.

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 exceed this range when conditions warrant using leverage to make strategic acquisitions. At December 31, 2007, for example, our debt-to-book capitalization ratio was 42%, which was reduced from 49% at mid-year 2007. Subsequent to the acquisition of Houston Exploration in June 2007, our debt-to-book capitalization ratio increased to 49% as a result of the issuance of 7¼% senior notes due 2019 and debt assumed in the acquisition. However, strategic sales in 2007, including the Alaska Assets and a sales lease back transaction of previously owned drilling equipment, reduced our debt-to-book capitalization ratio to 42% at December 31, 2007.

We also employ a "free cash flow" business model where we expect each of our producing business units to generate cash flows from operations (before changes in working capital) equal to or in excess of the business unit's capital expenditures used in exploration and development activities. We believe this policy provides for sustainable and sensible growth while providing the opportunity to use leverage to capitalize on acquisition opportunities. Hedging is also an important part of our strategy to cushion our exposure to commodity price volatility. We have a board-approved policy related to commodity hedging activities. As of February 27, 2008, we have hedged, via swaps and collar instruments, approximately 75 Bcfe of our 2008 production.

At December 31, 2007, we had approximately $10 million of cash on hand and $703 million available under our credit facilities.

Business Unit Activities

The production volumes, estimated proved reserves, and exploration and development expenditures for our business units as of and for the year ended December 31, 2007 are summarized below. The acquisition of Houston Exploration on June 6, 2007 had a significant impact on the Western, Eastern, and Southern business units. Accordingly, the production volumes and the exploration and development expenditures reflected in the table below are not indicative of full-year results.

	Production Volumes			Estimated Proved Reserves	Exploration and Development Expenditures[(1)]
Business Unit	Natural Gas (MMcf)	Liquids (MBbls)	Total (MMcfe)	Total (Bcfe)	Total (In Thousands)
Western	28,261	3,892	51,613	767.9	$278,701
Eastern	24,102	1,498	33,090	600.3	227,587
Southern	29,327	573	32,765	442.6	103,614
Canada	25,079	1,060	31,439	252.1	173,212
International[(2)]	—	—	—	56.3	15,853
Alaska[(3)]	1,273	922	6,805	—	4,601
Total	108,042	7,945	155,712	2,119.2	$803,568

(1) Includes estimated discounted asset retirement obligations of $1.4 million.

(2) All estimated proved reserves in the International business unit are in Italy.

(3) On August 27, 2007, Forest sold its Alaska Assets to PERL.

Western

The Western business unit's operations are located in the Texas Panhandle, West Texas, New Mexico, North Dakota, western Oklahoma, Colorado, Utah, and Wyoming. A significant area of activity for the Western business unit is in the Buffalo Wallow area located in Hemphill and Wheeler Counties in the Texas Panhandle. In 2007, we drilled 63 gross wells in the Buffalo Wallow area and plan to drill over 70 gross wells in 2008 targeting the Granite Wash and Atoka sands. As of December 31, 2007, we have identified approximately 700 non-proved potential locations in the Buffalo Wallow area, some of which have been approved for 20 acre downspacing. Current production from the Buffalo Wallow area represents approximately 35% of the Western business unit's total production. Capital expenditures in the Buffalo Wallow area are expected to comprise approximately $180 million of the business unit's 2008 capital expenditure budget of approximately $300 million.

The Western business unit added the Rocky Mountain leasehold positions acquired from Houston Exploration in 2007 including the Niobrara area in eastern Colorado and the Uinta Basin in western Utah. The Niobrara area has a significant number of potential drilling locations on approximately 475,000 net acres. With attractive, low risk, low decline rates, and low development costs, we expect to further optimize the gas gathering infrastructure and drill approximately 25 wells in the Niobrara field in 2008 utilizing 3D seismic. Our leaseholds in the Uinta Basin also have a significant number of potential drilling locations on approximately 100,000 net acres with substantial gas resource in place. Although we decreased the level of activity in the Uinta Basin in 2007 to allocate capital on higher rate-of-return projects in East Texas and the Arkoma Basin, we plan to continue a consistent level of activity in 2008 as we believe field economics have improved since 2007.

Eastern

The Eastern business unit's operations are located in East Texas, Arkansas, and Louisiana. The business unit's most significant area of focus has been in the Cotton Valley trend in East Texas since the initial acquisition of 26,000 net acres in early 2006. Since the initial acquisition, we have drilled a total of 83 net wells targeting multi-pay zones including the upper and lower Cotton Valley Taylor sands and, together with the additional net acreage acquired from the Houston Exploration acquisition, our net acreage position has increased to over 60,000 net acres. In 2008, we expect to drill over 50 gross wells including 12 horizontal wells on large undeveloped acreage in blocks in the area. The Eastern business unit also added another core area in the Arkoma Basin in western Arkansas as a result of the Houston Exploration acquisition. The Arkoma Basin has over 39,000 net acres and provides for additional low risk, low cost repeatable drilling opportunities with downspacing potential. In addition to a significant amount of surface work that commenced in 2007 and will continue in 2008, we plan to drill over 100 gross wells in the Arkoma Basin in 2008. Current production from the East Texas and the Arkoma Basin properties represents approximately 75% of the Eastern business unit's total production. We expect capital expenditures in these areas to comprise approximately $195 million of the business unit's 2008 capital expenditure budget of approximately $285 million.

Southern

The Southern business unit's operations are located in South Texas. The business unit's core operations include the Charco and Rincon fields acquired from Houston Exploration as well as the Katy and McAllen Ranch fields, which are legacy Forest properties. With the utilization of an extensive seismic database, we have identified a significant number of drilling locations in South Texas, and we plan to drill approximately 59 wells in the area in 2008. In 2008, we also plan to continue our extensional and infill drilling and recompletion program in the Katy field after achieving excellent results in 2007. Current production from the Rincon, Charco, Katy and McAllen Ranch fields represents approximately 65% of the Southern business unit's total production. Capital expenditures in the Rincon, Charco, Katy and McAllen Ranch fields are expected to comprise approximately $125 million of the business unit's 2008 capital expenditure budget of approximately $215 million.

Canada

The Canada business unit's operations are located primarily in central Alberta. The Canada business unit's primary area of focus is in the Deep Basin in central Alberta. In 2007, a total of 45 gross wells were drilled utilizing new fracture stimulation techniques resulting in the best wells drilled in the area to date by Forest in terms of initial production rates. We plan to drill approximately 35 gross wells in the Deep Basin in 2008. With the business unit's Wild River field anticipated to reach full development of its Cretaceous zones on 160-acre spacing, we plan to direct further capital at Sundance/Ansell, a multi-zone, Cretaceous play similar to Wild River in 2008 and focus on further development of additional reservoirs in the Wild River field. The Canada business unit also expanded its acreage position in the Deep Basin in 2007 to approximately 73,000 gross acres, with extensive 3D seismic coverage. Current production from the Deep Basin represents approximately 50% of the Canada business unit's total production. Capital expenditures in the Deep Basin are expected to be approximately $80 million of the business unit's 2008 capital expenditure budget of approximately $140 million.

International

The International business unit's operations are located in Italy and South Africa. In 2007, the International business unit drilled and completed two wells in Italy, which established estimated proved reserves of approximately 56 Bcfe as of December 31, 2007. Production from these wells is expected to come on line in 2009. In South Africa, the 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 sales contracts for the Ibhubesi field. See "*Acreage*" below, for further details.

Reserves

The following table shows our estimated quantities of proved reserves as of December 31, 2007 and 2006. Substantially all estimated proved reserves are currently located in North America. See Note 16 to the Consolidated Financial Statements for additional information regarding estimated proved reserves.

	December 31,	
	2007	2006
Proved developed:		
Natural gas (MMcf)	1,092,075	566,139
Liquids (MBbls)	66,597	78,280
Total (MMcfe)	1,491,657	1,035,819
Proved undeveloped:		
Natural gas (MMcf)	460,301	211,900
Liquids (MBbls)	27,879	34,584
Total (MMcfe)	627,575	419,404
Total proved:		
Natural gas (MMcf)	1,552,376	778,039
Liquids (MBbls)	94,476	112,864
Total (MMcfe)	2,119,232	1,455,223

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 2007, we filed estimates of our oil and gas reserves as of December 31, 2006 with the DOE, which were consistent with the reserve data reported for the year ended December 31, 2006 in Note 16 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. We engage independent reserve engineers to audit a substantial portion of our reserves. 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 our year-end proved reserves, discounted at 10% per annum, for each country in which we own 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 reserve definition and cost and price parameters specified by the Securities and Exchange Commission ("SEC").

For the year-end 2007, 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 81% of our reserves, as of December 31, 2007, 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 2007, we drilled a total of 495 gross wells, of which 52 were classified as exploration and 443 were classified as development. Our 2007 drilling program achieved a 96% success rate. The following table summarizes the number of wells drilled during 2007, 2006, and 2005, 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, 2007, we had 40 gross (28 net) wells in progress in the United States and 14 gross (8 net) wells in progress in Canada.

	Year Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Gas wells	392	210	210	52	232	32
Oil wells	34	29	13	11	16	14
Non-productive(1)	17	14	1	1	3	3
Total	443	253	224	64	251	49
Exploratory wells, completed as:						
Gas wells	41	28	135	68	100	51
Oil wells	6	2	15	9	31	27
Non-productive(1)	5	3	8	5	10	5
Total	52	33	158	82	141	83

(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. A well bore with multiple completions is counted as only one well. As of December 31, 2007, Forest owned interests in 458 gross wells containing multiple completions. The following table summarizes our productive wells as of December 31, 2007, all of which are located in the United States, Canada, and Italy:

	United States				Canada				Italy				Total	
	Operated Wells		Non-operated Wells[1]		Operated Wells		Non-operated Wells		Operated Wells		Non-operated Wells		Operated and Non-operated Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gas	2,674	2,560	3,316	176	375	295	251	70	2	2	—	—	6,618	3,103
Oil	2,020	1,987	604	56	246	221	95	20	—	—	—	—	2,965	2,284
Total	4,694	4,547	3,920	232	621	516	346	90	2	2	—	—	9,583	5,387

(1) The large variance between gross and net non-operated wells is primarily a result of our ownership interest in approximately 2,589 gross gas wells in the San Juan Basin with an average working interest of approximately 5%.

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, 2007 and 2006. 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,							
	2007				2006			
	Developed Acreage		Undeveloped Acreage		Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States:								
Western[1]	353,754	217,814	1,128,547	789,494	262,461	154,267	207,190	103,820
Eastern[1]	172,633	113,557	282,298	139,101	115,554	64,034	229,797	118,497
Southern[1]	192,752	135,852	73,843	34,208	68,921	38,351	22,685	5,755
Alaska[2]	—	—	—	—	52,242	32,155	1,038,532	1,012,637
	719,139	467,223	1,484,688	962,803	499,178	288,807	1,498,204	1,240,709
Canada	286,016	157,737	852,704	375,398	267,157	151,645	1,082,504	581,746
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	1,204,638
Italy	2,500	2,250	288,543	287,911	—	—	654,896	654,014
	2,500	2,250	5,469,514	2,967,091	—	—	5,835,867	3,333,194
Total	1,007,655	627,210	7,806,906	4,305,292	766,335	440,452	8,416,575	5,155,649

(1) Changes in acreage positions for the Western, Eastern, and Southern business units from 2006 are primarily the result of the Houston Exploration acquisition in 2007, which included 1,279,883 gross acres and 926,047 net acres. 2006 acreage amounts have been reclassified among U.S. locations to conform with the 2007 business unit structure.

(2) The Alaska Assets were sold to PERL in August 2007.

At December 31, 2007, approximately 13% and 7% of our net undeveloped acreage in the United States and Canada was held under leases that have terms that will expire in 2008 and 2009, respectively, if not extended by exploration or production activities. In addition, approximately 170,000 net undeveloped acres in the Niobrara area in eastern Colorado are scheduled to expire in 2008 but are held under leases that may be extended for an additional five years. 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 implemented new legislation in 2004 that revised the regulations and 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 and have applied for a production right covering the geographic area of our other existing prospecting sublease. The government has not taken final action on these applications. Because the regulations implementing the new legislation are not final and the potential work obligations that could be imposed pursuant to any new rights, when and if they are granted, are still uncertain, we cannot predict whether these rights will meet our economic or operational requirements. If the rights do not meet our internal requirements, we may choose to relinquish these leases. See "*Our International operations may be adversely affected by currency fluctuations and economic and political developments*" in Part I, Item 1A—"Risk Factors", for further details.

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, 2007, 2006, and 2005.

	United States			Canada			Total Company		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**	**2007**	**2006**	**2005**
Natural Gas:									
Sales price received (per Mcf)	$ 5.95	6.21	7.53	5.29	5.07	6.70	5.79	5.83	7.38
Effects of energy swaps and collars (per Mcf)[1]	—	(.37)	(1.24)	—	—	—	—	(.25)	(1.02)
Average sales price (per Mcf)[1]	$ 5.95	5.84	6.29	5.29	5.07	6.70	5.79	5.58	6.36
Natural gas sales volumes (MMcf)	82,963	48,674	82,912	25,079	24,350	18,921	108,042	73,024	101,833
Liquids:									
Oil and Condensate:									
Sales price received (per Bbl)	$ 67.91	62.18	52.78	58.05	50.89	41.92	66.44	60.79	51.67
Effects of energy swaps and collars (per Bbl)[1]	—	(4.94)	(11.22)	—	—	—	—	(4.34)	(10.07)
Average sales price (per Bbl)[1]	$ 67.91	57.24	41.56	58.05	50.89	41.92	66.44	56.45	41.60
Natural gas liquids:									
Average sales price (per Bbl)	$ 39.32	32.02	29.61	43.54	41.40	36.15	39.75	33.85	30.76
Total liquids:									
Average sales price (per Bbl)[1]	$ 58.02	51.22	39.12	54.40	47.55	40.04	57.54	50.70	39.23
Liquids sales volumes (MBbls)	6,885	6,887	9,316	1,060	1,139	1,252	7,945	8,026	10,568
Average sales price (per Mcfe)[1]	**$ 7.18**	**7.08**	**6.38**	**6.05**	**5.69**	**6.69**	**6.96**	**6.72**	**6.43**
Total sales volumes (MMcfe)	**124,273**	**89,996**	**138,808**	**31,439**	**31,184**	**26,433**	**155,712**	**121,180**	**165,241**
Production costs (per Mcfe):									
Lease operating expenses	$ 1.09	1.41	1.30	1.00	.91	.71	1.08	1.28	1.21
Production and property taxes	.42	.40	.29	.11	.10	.11	.35	.32	.26
Transportation and processing costs	.08	.13	.10	.33	.32	.22	.13	.18	.12
Total production costs (per Mcfe)	**$ 1.59**	**1.94**	**1.69**	**1.44**	**1.32**	**1.04**	**1.56**	**1.78**	**1.58**

(1) Include the effects of hedging under cash flow hedge accounting in 2006 and 2005. 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, among other things, the credit-worthiness of potential purchasers and concentrations of credit risk. We believe that the loss of one or more of our current oil and gas purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption. In 2007, there were no purchasers who exceeded 10% of our total 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 Note 9 to the Consolidated Financial Statements 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 than we have. Because of the nature of our oil and gas assets and management's experience in exploiting our reserves and acquiring properties, management believes that we effectively compete in our markets.

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 Minerals Management Service, as applicable, may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (“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.

The majority of our Canadian operations are located in Alberta, Canada, and, in October 2007, the Alberta Government announced a new oil and gas royalty framework to take effect in January 2009. The new framework establishes new royalties for conventional oil, natural gas, and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects.

Under the new framework, the formula for conventional oil and natural gas royalties will be set by a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil will range from 0% to 50%. New natural gas royalty rates will range from 5% to 50%. Under the current royalty regime, royalty rates range from 10% to 35% for conventional oil and from 5% to 35% for natural gas.

The implementation of the new framework is subject to certain risks and uncertainties. The significant changes to the royalty regime require new legislation, changes to existing legislation and regulation, and development of proprietary software to support the calculation and collection of royalties. In addition, certain proposed changes contemplate further public and/or industry consultation. Accordingly, there may be modifications introduced to the new framework prior to its implementation on January 1, 2009. If the new framework is implemented in the same form as announced, the rate caps will be raised for conventional oil from $30 to $120 per barrel. The rate caps for natural gas will be raised from $3.90 to $17.50 per MMBtu. The tiers in conventional oil and natural gas that distinguish ‘vintages’ based on discovery date will be eliminated. Several special royalty programs for conventional oil and natural gas will also be extinguished, except for the Otherwise Flared Solution Gas Royalty Waiver Program and Deep Gas Drilling Program, both of which will be amended. The royalties for natural gas liquids will be set at 40% for pentanes, from the previous 22% to 50% for old tiers and 22% to 35% for new. The new royalties for butanes and propane will be 30%, from the current 15% to 30%. The Alberta government will extinguish the option to use the Corporate Average Price to determine natural gas royalties in lieu of a single reference price. If adopted in its current form, we expect that our royalty payments on our Canadian oil and gas sales will increase.

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, 2007, we had 728 employees. None of our employees is currently represented by a union for collective bargaining purposes.

Geographical Data

Forest operates in one industry segment. For information relating to our geographical operating segments, see Note 14 to the Consolidated Financial Statements of this Form 10-K.

Offices

Our corporate office is located in leased space at 707 17th Street, Denver, Colorado 80202. We maintain offices in Houston, Texas and Calgary, Alberta, Canada and also lease or own field offices in the areas in which we conduct operations.

Title to Properties

Title to our oil and gas properties is subject to royalty, overriding royalty, carried, net profits, working, and similar interests customary in the oil and gas industry. Under the terms of our bank credit facilities, we have granted the lenders a lien on 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.*

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 geological and engineering data demonstrate with reasonable certainty to be recoverable in future years 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 for recovery to occur.

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

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

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

Undeveloped Acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of 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 each of the committees of our Board of Directors (including the charters of the Audit Committee, Compensation Committee, and Nominating and Corporate Governance Committee), and codes of ethics for our directors and employees entitled "Code of Business Conduct and Ethics" and "Proper Business Practices Policy," respectively.

In May 2007, 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 have 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" included in this Form 10-K.

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;
- 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 operations outside the United States 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.

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.

Our business activities are subject to certain risks and hazards, including the risks discussed below. If any of these events should occur, it could materially and adversely affect our business, financial condition, cash flows, or results of operations. Further, these risks are not the only risks we face. We may experience additional risks and uncertainties not currently known to us or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations.

Oil and natural gas prices fluctuate due to a number of factors outside of our control, and declining prices will adversely affect our financial condition and results of operations. Our results of operations and future rate of growth depend upon the prices that we receive for our oil and natural gas. We sell most of our oil and gas at current prices rather than through fixed-price contracts. Historically, the markets for oil and natural gas have been volatile and are likely to remain volatile in the future. Oil and gas prices are currently at or near historical highs, and they may decline in the future. The prices we receive depend upon factors beyond our control, including among others:

- domestic and foreign supply, consumer demand for oil and gas, and market expectations regarding supply and demand;
- weather conditions;
- political instability and armed conflicts in oil-producing and gas-producing regions;
- actions by the Organization of Petroleum Exporting Countries (“OPEC”);
- domestic and worldwide economic conditions;
- the price and availability of foreign exports and the availability of alternate fuels; and
- governmental regulations and taxes.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Approximately 73% of our estimated proved reserves at December 31, 2007 was natural gas, and, as a result, our financial results in 2008 will be more sensitive to fluctuations in natural gas prices.

To the extent we have not hedged our production, a significant or extended decline in the prices of oil and gas below current levels will negatively impact:

- our revenues, cash flows, profitability, and earnings;
- our ability to make capital expenditures;
- our ability to replace our production and our future rate of growth;
- our ability to meet our financial obligations;
- our ability to raise capital or borrow money and our cost of such capital;

- the amount that we are allowed to borrow under our credit facilities; and
- the amount of oil and natural gas that we can produce economically.

We have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy. We incur, and will continue to incur, substantial capital expenditures for the acquisition, development, and exploration of our oil and natural gas reserves. In 2007, 2006, and 2005, we incurred approximately $3.0 billion, $943 million, and $854 million on capital expenditures, respectively, including approximately $2.2 billion, $316 million, and $314 million on property acquisitions. Our exploration and development expenditures budget for 2008 is approximately $900 million to $1 billion. We intend to finance our ongoing capital expenditures primarily through cash flow from operations and our bank credit facilities, and any exceptional expenditures with public or private equity and debt offerings.

Our ability to access these sources of capital will depend upon a number of factors, some of which are outside our control. These factors include:

- oil and natural gas prices;
- the value and performance of Forest debt and equity securities;
- the credit ratings assigned to Forest by independent rating agencies; and
- general economic and financial market conditions.

For example, oil and natural gas prices are currently at or near historic highs, and a significant decline in oil and natural gas prices would reduce our cash flow and could affect our access to the capital markets. Further, our access to funds under our credit facilities is based on a global borrowing base, which is based on our estimated proved reserves, and is redetermined semi-annually by the lenders and may be redetermined at other times during the year at the option of Forest or the lenders. The global borrowing base may be reduced if oil and natural gas prices decline, or if we have downward revisions in estimates of our proved reserves, which may adversely affect our planned capital expenditures.

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, including the 8% senior notes that will come due on June 15, 2008, at current levels for the foreseeable future. If revenues decrease, however, and we are unable to obtain additional debt or equity financing or alternative sources of funds, we may have to reduce our capital expenditures and may lack the capital necessary to replace our reserves or maintain our production at current levels.

We have substantial indebtedness and may incur more debt in the future, and our leverage may materially affect our operations and financial condition. We have incurred substantial debt. At December 31, 2007, the principal amount of our outstanding consolidated debt was approximately $1.7 billion, including $294 million outstanding under our combined U.S. and Canadian credit facilities. Our outstanding consolidated debt represented approximately 42% of our total capitalization at December 31, 2007. Further, we may incur more debt in the future, including in connection with acquisitions and refinancings. The level of our debt has several important effects on our business and operations; among other things, it may:

- require us to use a significant portion of our cash flow to pay principal and interest on the debt, which will reduce the amount available to fund working capital, capital expenditures, and other general purposes;
- increase our costs as our access to the capital markets and our cost of borrowing is predicated on the credit ratings assigned by third party rating agencies, which have in the past and may in

the future downgrade their ratings of our debt and other obligations due to changes in market conditions, our debt level or our financial condition;

- limit our access to the capital markets, increase our borrowing costs, and impact the terms, conditions, and restrictions contained in our debt agreements, including the addition of more restrictive covenants;
- impact our flexibility in planning for and reacting to changes in our business as covenants and restrictions contained in our existing and possible future debt arrangements may require that we meet certain financial tests and place restrictions on the incurrence of additional indebtedness;
- place us at a disadvantage compared to similar companies in our industry that have less debt; and
- make us more vulnerable to economic downturns and adverse developments in our business.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, domestic and foreign economic conditions, regulatory, and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance the debt, sell assets, or sell shares of our stock on terms that we do not find attractive, if it can be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our credit facilities and the indentures pertaining to our outstanding senior notes could result in a default under these agreements, which could adversely affect our business, financial condition, and results of operations.

For example, of the principal amount of outstanding consolidated debt at December 31, 2007, $265 million will come due in June 2008. Our ability to refinance this debt will depend on our cash flow and our borrowing base and ability to access funds under our credit facility. If we do not have sufficient funds available, we may need to access the capital markets. Over the recent months, the capital markets have limited the availability of funds due to distressed conditions in the sub-prime securities market and other factors. We can not predict whether we will need to access the capital markets to refinance any portion of our debt obligations or whether the market conditions existing at such time will allow us to obtain the necessary funds.

Our use of hedging transactions could result in financial losses or reduce our income. To reduce our exposure to fluctuations in oil and natural gas prices, we have and expect in the future to enter into derivative instruments (or, hedging agreements) for a portion of our oil and natural gas production. Our commodity hedging agreements are limited in duration, usually for periods of one year or less; however, in conjunction with acquisitions, we sometimes enter into or acquire hedges for longer periods. As of February 27, 2008, we had hedged, via commodity swaps and collar instruments, approximately 75 Bcfe of our 2008 production. Our hedging transactions expose us to certain risks and financial losses, including, among others:

- we may be limited in receiving the full benefit of increases in oil and natural gas prices as a result of these transactions;
- we may hedge too much or too little production depending on how oil and natural gas prices fluctuate in the future;
- there is a change to the expected differential between the underlying price and the actual price received; and
- a counterparty to a hedging arrangement may default on its obligations to Forest.

For further information concerning our commodity price hedging transactions and information concerning prices, market conditions, and our swap and collar hedging agreements, see Part II, Item 7A—"Qualitative and Quantitative Disclosures about Market Risk—Commodity Price Risk" of this Form 10-K, and Note 9 to the Consolidated Financial Statements.

Our proved reserves are estimates and depend on many assumptions. Any material inaccuracies in these assumptions could cause the quantity and value of our oil and gas reserves, and our revenue, profitability, and cash flow, to be materially different from our estimates. The proved oil and gas reserve information and the related future net revenues information included in this Form 10-K represent only estimates, which are prepared by our internal staff of engineers. Estimating quantities of proved oil and natural gas reserves is a subjective, complex process and depends on a number of variable factors and assumptions. To prepare estimates of economically recoverable oil and natural gas reserves and future net cash flows:

- we analyze historical production from the area and compare it to production rates from other producing areas;
- we analyze available technical data, including geological, geophysical, production, and engineering data, and the extent, quality, and reliability of this data can vary; and
- we must make various economic assumptions, including assumptions about prices, production costs, severance and excise taxes, capital expenditures, and workover and remedial costs.

Ultimately, actual production, revenues, and expenditures relating to our reserves will vary from our estimates. Any significant inaccuracies in our assumptions or changes in operating conditions could cause the estimated quantities and net present value of the reserves shown in this Form 10-K to be different from our estimates.

You should not assume that any present value of future net cash flows from our producing reserves shown in this Form 10-K is the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations and, or taxes. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

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. In addition, our ceiling test cushion is subject to fluctuation as a result of our corporate development activity, which is difficult to fully assess prior to completion.

Our failure to replace our reserves could result in a material decline in our reserves and could adversely affect our financial condition. In general, our proved reserves decline when oil and natural gas is produced, unless we are able to conduct successful exploitation, exploration, and development activities, or acquire additional properties containing proved reserves, or both. Our future performance, therefore, is highly dependent upon our ability to find, develop and, or acquire additional reserves. Exploring for, developing, or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments if our cash flows from operations decline or external sources of capital become limited or unavailable. We cannot assure you that our future exploitation, exploration, development, and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs.

Drilling oil and natural gas wells is a high-risk activity and subjects us to a variety of factors that we cannot control. Drilling oil and natural gas wells involves numerous risks, including the risk that we may not encounter commercially productive oil or natural gas reservoirs. The presence of unanticipated pressures or irregularities in formations, miscalculations, or accidents may cause our drilling activities to be unsuccessful and result in significantly higher than expected costs and, or the total loss of our investment. Further, the cost of drilling, completing, and operating wells is often uncertain. Our drilling operations may be shortened, delayed, curtailed, or canceled as a result of a variety of factors, many of which are beyond our control, including:

- unexpected drilling conditions;
- geological irregularities or pressure in formations;
- equipment failures or accidents;
- costs of, or shortages or delays in the availability of, drilling rigs and related equipment;
- shortages in labor;
- adverse weather conditions;
- fires, explosions, blow-outs, or surface cratering; and
- restricted access to land necessary for drilling or laying pipelines.

Forest has a drilling subsidiary that provides services to Forest and third parties. The operations of our drilling subsidiary are subject to various factors outside of our control, including the factors described above, and the risks associated with conducting drilling activities, such as natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases, any of which could result in substantial losses, injuries or loss of life, environmental damage and clean-up responsibilities, and the suspension of our operations.

We cannot assure you that any new wells we drill will be productive or that we will recover all or any portion of our investment.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control. The marketability of our production depends in part upon the availability, proximity, and capacity of pipelines, natural gas gathering systems, and processing facilities. Any significant change in market factors affecting these infrastructure facilities, as well as delays in the construction of new infrastructure facilities, could harm our business. We deliver the majority of our oil and natural gas through gathering facilities that we do not own. As a result, we are subject to the risk that these facilities may be temporarily unavailable due to mechanical reasons or market conditions, or may not be available to us in the future. We have formed a natural gas gathering subsidiary to hold pipeline and related equipment, which currently operates solely within the State of Texas. The subsidiary transports natural gas produced by Forest as well as third parties.

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 activities performed by our drilling subsidiary and gas gathering subsidiary involve risks. These operating risks include the risk of fire, explosions, blow-outs, pipe failure, damaged drilling and oil field equipment, abnormally pressured formations, and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures, or discharges of toxic gases. If any of these industry operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources, and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. Generally, pollution related environmental risks are not fully insurable. We do not insure against business interruption. We cannot assure that our insurance will be fully adequate to cover other losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

Our international operations may be adversely affected by currency fluctuations and economic and political developments. We currently have oil and gas properties and operations in Canada, Italy, Gabon, and South Africa. As a result, we are exposed to the risks of international operations, including political and economic developments, royalty and tax increases, changes in laws or policies affecting our exploration and development activities, and currency exchange risks, as well as changes in the policies of the United States affecting trade, taxation, and investment in other countries.

We have significant operations in Canada. In 2007, the revenues and expenses of such operations represented approximately 18% of our consolidated oil and gas revenues and 19% of our consolidated production costs. The revenues and expenses of these operations are denominated in Canadian dollars. As a result, the profitability of our Canadian operations is subject to the risk of fluctuation in the exchange rates between the U.S. dollar and Canadian dollar. In addition, our Canadian operations may be adversely affected by recent regulatory developments. The majority of our Canadian operations are located in Alberta, Canada, and in October 2007, the Alberta Government announced a new oil and gas royalty framework to take effect in January 2009. The new framework establishes new royalties for conventional oil, natural gas, and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new framework, the formula for conventional oil and natural gas royalties will be set by a sliding rate formula, dependent on the market price and production volumes. Royalty rates for conventional oil will range from 0% to 50%. New natural gas royalty rates will range from 5% to 50%. Under the current royalty regime, royalty rates range from 10% to 35% for conventional oil and from 5% to 35% for natural gas.

The implementation of the new royalty framework in Canada is subject to risks and uncertainties. The significant changes to the royalty regime require new legislation, changes to existing legislation and regulation, and development of proprietary software to support the calculation and collection of royalties. In addition, certain proposed changes contemplate further public and/or industry consultation. Accordingly, there may be modifications introduced to the new framework prior to its January 1, 2009 implementation. If the new framework is implemented in the same form as announced, the rate caps will be raised for conventional oil from $30 to $120 per barrel. The rate caps for natural gas will be raised from $3.90 to $17.50 per MMBtu. The tiers in conventional oil and natural gas that distinguish 'vintages' based on discovery date will be eliminated. Several special royalty programs for conventional oil and natural gas will also be extinguished, except for the Otherwise Flared Solution Gas Royalty Waiver Program and Deep Gas Drilling Program, both of which will be amended. The royalties for natural gas liquids will be set at 40% for pentanes, from the previous 22% to 50% for old tiers and 22% to 35% for new. The new royalties for butanes and propane will be 30%, from the current 15% to 30%. The Alberta government will extinguish the option to use the Corporate Average Price to determine natural gas royalties in lieu of a single reference price. If adopted in its current form, we expect that our royalty payments on our Canadian oil and gas sales will increase.

Although we do not have material operations in Italy, Gabon, and South Africa, our ongoing operations may be adversely affected by political, economic, and regulatory developments, changes in the local royalty and tax regimes, and currency fluctuations. In Italy, we have increased the level of our drilling and related exploration and development activities over the last several years. In 2007, we successfully completed two wells in Italy and are currently planning to construct pipelines and facilities to deliver the natural gas. During 2007, we assigned estimated proved reserves to these properties and expect to bring these wells on production in the first half of 2009.

In South Africa, we have an interest in offshore properties that have tested natural gas, although we have not assigned any proved reserves to these properties as we have not yet established commercial sales contracts. 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. In 2004, the South African government implemented new legislation that revises the regulations and 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 and have applied for a production right covering the geographic area of our other existing prospecting sublease. The government has not taken final action on these applications. We cannot predict whether these applications will be granted. Further, because not all of the regulations implementing the new legislation are final and the potential work obligations that may be imposed pursuant to the rights, when and if they are granted, are still uncertain, we cannot predict whether these rights will meet our economic or operational requirements. If the rights do not meet our internal requirements, we may choose to relinquish these leases and lose our investment, which totals approximately $50 million.

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 than we have. In addition, oil and gas producers are increasingly facing competition from providers of non-fossil energy, and government policy may favor those competitors in the future. Many of these competitors have financial and other resources substantially greater than ours. We can give no assurance that we will be able to compete effectively in the future and that our financial condition and results of operations will not suffer as a result.

Our growth depends 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;
- our ability to reasonably estimate or assess the recoverable volumes of reserves;
- rates of future production and future net revenues attainable from reserves;

• future operating and capital costs;

• 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.

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 regulations, Canadian federal and provincial governmental laws and regulations, and local and federal regulations in Italy. These regulations may be changed in response to economic or political conditions. Matters subject to these governmental regulations 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 our operations, the spacing of wells, and unitization and pooling of properties, and taxation. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions that could delay, limit or prohibit certain of our operations. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies may restrict the rates of flow of oil and gas wells below actual production capacity. Further, a significant spill from one of our facilities could have a material adverse effect on our results of operations, competitive position, or financial condition. The laws in the United States, Canada, and Italy regulate, among other things, the production, handling, storage, transportation, and disposal of oil and gas, by-products from oil and gas, and other substances and materials produced or used in connection with oil and gas operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations. We may not be able to recover some or any of these costs from insurance.

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

Item 1B. Unresolved Staff Comments.

As of December 31, 2007, we did not have any SEC staff comments that have been unresolved for more than 180 days.

Item 2. Properties.

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

Item 3. Legal Proceedings.

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

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

No matter was submitted to a vote of our shareholders during the fourth quarter of the fiscal year ended December 31, 2007.

Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of February 27, 2008.

Name	Age	Years with Forest	Office[1]
H. Craig Clark	51	7	President and Chief Executive Officer, and a member of the Board of Directors since July 2003. Mr. Clark joined Forest in September 2001 and served as President and Chief Operating Officer through July 2003. Mr. Clark was employed by Apache Corporation, an oil and gas exploration and production company, from 1989 to 2001, where he served in various management positions including Executive Vice President—U.S. Operations and Chairman and Chief Executive Officer of Pro Energy, an affiliate of Apache.
David H. Keyte	51	20	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.
J.C. Ridens	52	4	Executive Vice President and Chief Operating Officer since November 2007. Since joining Forest in April 2004, Mr. Ridens has served as Senior Vice President for the Gulf Region, the Southern Region and most recently the Western Region. From 2001 to 2004, Mr. Ridens was employed by Cordillera Energy Partners, LLC, as Vice President of Operations and Exploitation. From 1996 to 2001, he served in various capacities at Apache Corporation.
Cecil N. Colwell	57	19	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	51	5	Senior Vice President since September 2003. From 1987 to 2000, he served in various capacities at Atlantic Richfield Co. Before joining Forest Mr. Gurule served on the boards of several local community and non-profit organizations and managed his own investment portfolio.
Cyrus D. Marter IV	44	6	Senior Vice President, General Counsel and Secretary since November 2007. Mr. Marter served as Vice President, General Counsel and Secretary from January 2005 to November 2007, as Associate General Counsel from October 2004 to January 2005, and as Senior Counsel from June 2002 until October 2004. Prior to joining Forest, Mr. Marter was a partner of the law firm of Susman Godfrey L.L.P. in Houston, Texas.
Glen J. Mizenko	45	7	Senior Vice President, Business Development and Engineering since May 2007. Mr. Mizenko joined Forest in January 2001 as Manager Corporate Development and New Ventures. In October 2003, he was promoted to the position of Director, Business Development. In May 2005, he was promoted to Vice President, Business Development. Prior to joining Forest, Mr. Mizenko held various positions in reservoir engineering, reserves reporting, development planning, and operations management with Shell Oil, Benton Oil & Gas, and British Borneo Oil and Gas PLC.
Mark E. Bush	48	10	Vice President, Eastern Region since April 2007. Mr. Bush joined Forest in June 1997 as Production Engineer in the Gulf of Mexico Region and was subsequently promoted to Offshore Production Engineering Manager and Production Engineering Manager, both in the Gulf Coast Region and its successor, the Eastern Region. Prior to joining Forest Oil, he worked for Oryx Energy Company (formerly Sun E&P) in various production engineering assignments in the Gulf of Mexico and South Texas.
Stephen T. Harpham	46	6	Vice President, Western Region since November 2007. Mr. Harpham joined Forest in January 2002 and served as a Reservoir Engineer and subsequently Reservoir Engineering Manager. Prior to joining Forest, Mr. Harpham was a Technical Advisor with Ensign Oil & Gas Inc.
Ronald C. Nutt	50	*	Vice President, Southern Region since July 2007. Prior to joining Forest, from March 2007 to July 2007, Mr. Nutt worked for Constellation Energy Group as an Engineer, and from January 2003 to March 2007 at Scotia Waterous as Vice President, Engineering.

Name	Age	Years with Forest	Office(1)
Victor A. Wind	34	3	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, LLP.

(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.

(*) Denotes less than one year of service.

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 15, 2008, our Common Stock was held by 1,119 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 2006 or 2007. On February 27, 2008, the closing price of Forest Common Stock was $49.54.

		Common Stock		Common Stock (As Adjusted)(1)	
		High	Low	High	Low
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
2007	First Quarter	$34.25	28.84	34.25	28.84
	Second Quarter	45.05	33.26	45.05	33.26
	Third Quarter	44.72	37.43	44.72	37.43
	Fourth Quarter	52.25	42.78	52.25	42.78

(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 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) the indentures concerning Forest's 8% senior notes due 2008, Forest's 8% senior notes due 2011, Forest's 7¾% senior notes due 2014, and Forest's 7¼% senior notes due 2019, and (iv) Forest's United States and Canadian bank credit facilities dated as of June 6, 2007. 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. 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. 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."

Issuer Purchases of Equity Securities

The table below sets forth information regarding repurchases of our Common Stock during the 3-month fiscal quarter and year ended December 31, 2007. The shares repurchased represent shares of our Common Stock that employees elected to surrender to Forest to satisfy their tax withholding obligations upon the vesting of shares of restricted stock. Forest does not consider this a share buyback program.

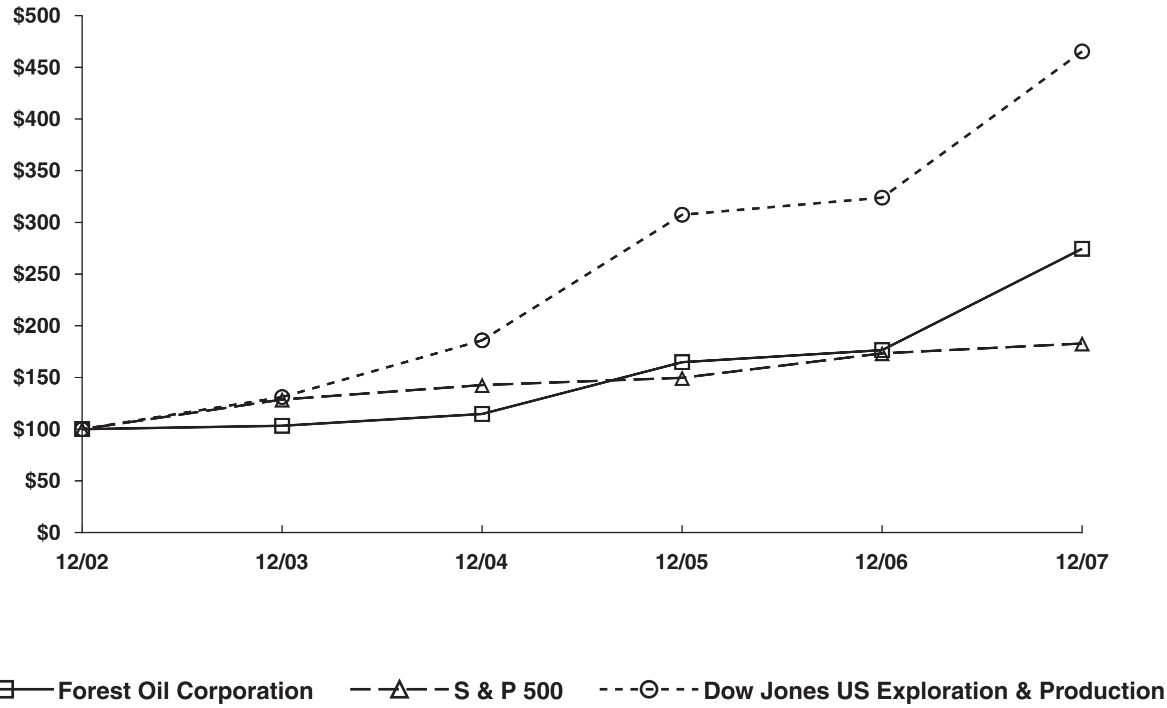
Period	Total # of Shares Purchased	Average Price Per Share	Total # of Shares (or units) Purchased as Part of Publicly Announced Plans or Programs	Maximum # (or Approximate Dollar Value) of Shares that May yet be Purchased Under the Plans or Programs
January 2007	—	$ —	—	—
February 2007	8,258	33.51	—	—
March 2007	38	31.53	—	—
April 2007	—	—	—	—
May 2007	75	40.86	—	—
June 2007	1,400	43.78	—	—
July 2007	—	—	—	—
August 2007	—	—	—	—
September 2007	38	40.71	—	—
October 2007	—	—	—	—
November 2007	—	—	—	—
December 2007	19,760	48.83	—	—
Fourth Quarter Total	19,760	48.83	—	—
2007 Total	29,569	44.26	—	—

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2002 (and the reinvestment of dividends thereafter) in each of Forest Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. We believe that the Dow Jones U.S. Exploration and Production Index is meaningful, because it is an independent, objective view of the performance of other similarly-sized energy companies.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Forest Oil Corporation, The S&P 500 Index
And The Dow Jones US Exploration & Production Index



*$100 Invested on 12/31/02 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

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, 2007. 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 June 6, 2007, Forest completed the acquisition of Houston Exploration. On August 27, 2007, we sold all of our Alaska assets. On March 2, 2006, Forest completed the spin-off of its offshore Gulf of Mexico operations. See *"Acquisition of Houston Exploration," "Sale of Alaska Assets,"* and *"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,				
	2007	2006	2005	2004	2003
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Revenues	$1,083,892	819,992	1,072,045	912,898	657,178
Earnings from continuing operations	169,306	166,080	151,568	123,126	90,228
Income (loss) from discontinued operations, net of tax[1]	—	2,422	—	(575)	(7,731)
Cumulative effect of change in accounting principle, net of tax[2]	—	—	—	—	5,854
Net earnings	$ 169,306	168,502	151,568	122,551	88,351
Basic earnings per share:					
Earnings from continuing operations	$ 2.22	2.67	2.47	2.16	1.82
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	$ 2.22	2.71	2.47	2.15	1.79
Diluted earnings per share:					
Earnings from continuing operations	$ 2.18	2.62	2.41	2.12	1.79
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	$ 2.18	2.66	2.41	2.11	1.75
Total assets	$5,695,548	3,189,072	3,645,546	3,122,505	2,683,548
Long-term debt	$1,503,035	1,204,709	884,807	888,819	929,971
Shareholders' equity	$2,411,811	1,434,006	1,684,522	1,472,147	1,185,798
OPERATING DATA					
Annual production:					
Gas (MMcf)	108,042	73,024	101,833	107,366	96,977
Liquids (MBbls)	7,945	8,026	10,568	10,837	8,701
Average sales price[3]:					
Gas (per Mcf)	$ 5.79	5.58	6.36	5.34	4.53
Liquids (per Bbl)	$ 57.54	50.70	39.23	31.05	24.77

(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 Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations"* on January 1, 2003.

(3) Includes the effects of hedging under cash flow hedge accounting in 2003 to 2006.

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—"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: Western, Eastern, Southern, Canada, and International. We conduct exploration and development activities in each of our geographical segments; however, substantially all of our estimated proved reserves and all of our producing properties are located in North America. Forest's total estimated proved reserves as of December 31, 2007 were approximately 2.1 Tcfe. At December 31, 2007, approximately 85% of our estimated proved oil and gas reserves were in the United States, approximately 12% were in Canada, and approximately 3% were in Italy.

Acquisition of Houston Exploration

On June 6, 2007, Forest completed the acquisition of The Houston Exploration Company ("Houston Exploration") in a cash and stock transaction totaling approximately $1.5 billion and the assumption of Houston Exploration's debt. Houston Exploration was an independent natural gas and oil producer engaged in the exploration, development, exploitation, and acquisition of natural gas and oil reserves in North America. Houston Exploration had operations in four producing regions within the United States: South Texas, East Texas, the Arkoma Basin of Arkansas, and the Uinta and DJ Basins in the Rocky Mountains. The principal factors management considered in making the acquisition included the mix of complementary high-quality assets in certain 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. At the time of the acquisition in June 2007, Forest estimated the Houston Exploration oil and gas reserves to be 653 Bcfe, of which 71% were classified as proved developed and the remaining amounts were classified as proved undeveloped. Pursuant to the terms and conditions of the agreement and plan of merger ("Merger Agreement"), Forest paid total merger consideration of $750 million in cash and issued approximately 24 million common shares, valued at $30.28 per share. The per share value of the Forest common shares issued was calculated as the average of Forest's closing share price for a five day period surrounding the announcement date of the acquisition on January 7, 2007. The cash component of the merger consideration was financed from a private placement of $750 million of 7¼% senior notes due 2019 and borrowings under our $1.0 billion second amended and restated credit facilities that were executed on June 6, 2007. Immediately following the completion of the merger, Forest repaid all of Houston Exploration's outstanding bank debt totaling $177 million. The revenues and expenses associated with Houston Exploration have been included in Forest's Consolidated Statement of Operations since June 6, 2007, the date the acquisition closed.

Sale of Alaska Assets

On August 27, 2007, Forest sold all of its assets located in Alaska (the "Alaska Assets") to Pacific Energy Resources Ltd. ("PERL"). Forest estimated the proved oil and gas reserves associated with the Alaska Assets at closing to be 173 Bcfe. The total consideration received for the Alaska Assets included $400 million in cash, 10 million shares of PERL common stock (subject to certain restrictions), and a zero coupon senior subordinated note from PERL due 2014 in the principal amount at stated maturity of $60.8 million.

Spin-off of Offshore Gulf of Mexico Operations

On March 2, 2006, Forest completed the spin-off of its offshore Gulf of Mexico operations by means of a special 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 approximately 50.6 million 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. Forest estimated the proved oil and gas reserves associated with the Spin-off to be 313 Bcfe.

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 the associated liability were included in the Spin-off. Subsequent to the closing, in 2006 Forest received additional net cash proceeds of $21.7 million from MERI for a total of $197.8 million. In accordance with the transaction agreements, Forest and MERI each submitted post-closing adjustments, from which Forest paid MERI a total of $5.8 million during 2007. Additional adjustments to the cash amount may occur during 2008 pending the resolution of certain accounting matters that are the subject of ongoing arbitration between Forest and MERI. The arbitration is currently expected to be concluded in the second half of 2008.

Other 2007 Highlights

Forest's other 2007 highlights were as follows:

- Oil and gas production in 2007 increased 28% to 156 Bcfe from 121 Bcfe in 2006.
- Forest's year-end estimated proved reserves were a record 2,119 Bcfe, 664 Bcfe higher than 2006's year-end estimated proved reserves of 1,455 Bcfe, primarily as a result of the Houston Exploration acquisition and additional discoveries offset by the sale of the Alaska Assets.
- On June 6, 2007, Forest issued $750 million of 7¼% senior notes due 2019 (the "7¼% Notes"). The net proceeds from the 7¼% Notes offering of $739.2 million, after deducting initial purchaser discounts, were used to fund a portion of the cash consideration for Forest's acquisition of Houston Exploration.
- On June 6, 2007, Forest entered into second amended and restated U.S. and Canadian credit facilities in connection with the Houston Exploration acquisition which will mature in 2012. Initial commitments consist of a U.S. facility of $850 million and a Canadian facility of $150 million for a total of $1.0 billion.

2008 Outlook

In 2008, we expect to continue our development and exploitation activities on our North American assets for which we expect continued production growth. Our exploration and development expenditures budget for 2008 is $900 million to $1 billion. Most of this capital budget will be directed to our large drilling programs in the Buffalo Wallow field in the Texas Panhandle, the Deep Basin in Alberta, Canada, the Rincon, Charco, Katy, and McAllen Ranch fields in South Texas, the Cotton Valley in East Texas, and the Arkoma Basin in Arkansas. Our inventory of exploitation and development projects is significant, which should provide us good visibility of future production growth.

Additionally, together with our continued production cost reduction initiatives, the acquired lower-cost natural gas producing assets from Houston Exploration, and the sale of higher-cost oil producing Alaska Assets, we expect our future per-unit production costs in 2008 to be lower than previous years. However, with our production mix more heavily weighted towards natural gas production, our revenues will be more heavily dependent on natural gas prices than they have been in the past. Natural gas production is expected to make up approximately 75% of our total production mix in 2008 compared to approximately 60% in 2006.

We expect to continue to pursue asset acquisition opportunities in 2008, 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 2007. 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

For the year ended December 31, 2007, Forest reported net earnings of $169.3 million or $2.22 per basic share compared to net earnings of $168.5 million or $2.71 per basic share in 2006. The increase in net earnings in 2007 compared to 2006 was primarily due to increases in earnings from operations and realized hedging gains, offset by increased unrealized mark-to-market hedging losses and interest expense. 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 2005. The increase in net earnings in 2006 compared to 2005 was primarily due to an increase in net unrealized mark-to-market hedging gains, offset by decreased earnings from operations as a result of the Spin-off transaction discussed above. Discussion of the components of the changes in our annual results follows.

Revenues

Oil and gas production volumes, revenues, and weighted average sales prices, by product and location for the years ended December 31, 2007, 2006, and 2005, are set forth in the table below. This table does not include miscellaneous marketing and processing revenues of $.8 million, $5.5 million, and $9.5 million for the years ended December 31, 2007, 2006, and 2005, respectively.

	Year Ended December 31,											
	2007				2006				2005			
	Gas	Oil	NGLs	Total	Gas	Oil	NGLs	Total	Gas	Oil	NGLs	Total
	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(MMcf)	(MBbls)	(MBbls)	(MMcfe)
Production volumes:												
United States	82,963	4,504	2,381	**124,273**	48,674	5,243	1,644	**89,996**	82,912	7,412	1,904	**138,808**
Canada	25,079	793	267	**31,439**	24,350	739	400	**31,184**	18,921	844	408	**26,433**
Totals	108,042	5,297	2,648	**155,712**	73,024	5,982	2,044	**121,180**	101,833	8,256	2,312	**165,241**
Revenues (In Thousands):												
United States	$493,321	305,873	93,624	**892,818**	302,050	326,024	52,636	**680,710**	624,457	391,226	56,375	**1,072,058**
Canada	132,601	46,037	11,625	**190,263**	123,408	37,605	16,559	**177,572**	126,771	35,382	14,748	**176,901**
Total before hedging	625,922	351,910	105,249	**1,083,081**	425,458	363,629	69,195	**858,282**	751,228	426,608	71,123	**1,248,959**
Less hedging effects[1]	—	—	—	**—**	(17,893)	(25,920)	—	**(43,813)**	(103,292)	(83,150)	—	**(186,442)**
Totals	$625,922	351,910	105,249	**1,083,081**	407,565	337,709	69,195	**814,469**	647,936	343,458	71,123	**1,062,517**
Average sales price:												
United States	$ 5.95	67.91	39.32	**7.18**	6.21	62.18	32.02	**7.56**	7.53	52.78	29.61	**7.72**
Canada	5.29	58.05	43.54	**6.05**	5.07	50.89	41.40	**5.69**	6.70	41.92	36.15	**6.69**
Combined	5.79	66.44	39.75	**6.96**	5.83	60.79	33.85	**7.08**	7.38	51.67	30.76	**7.56**
Less hedging effects[1]	—	—	—	**—**	(.25)	(4.34)	—	**(.36)**	(1.02)	(10.07)	—	**(1.13)**
Totals	$ 5.79	66.44	39.75	**6.96**	5.58	56.45	33.85	**6.72**	6.36	41.60	30.76	**6.43**

[1] Commodity swaps and collars accounted for as cash flow hedges. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk" below concerning our hedging activities.

Production Volumes and Oil and Gas Revenues

Net oil and gas production in 2007 was 155.7 Bcfe or an average of 426.6 MMcfe per day, a 28% increase from 121.2 Bcfe or an average of 332.0 MMcfe per day in 2006. The net increase in oil and gas production was primarily attributable to the additional production associated with the Houston Exploration acquisition in June 2007, which was partially offset by the Spin-off in early March 2006 and the sale of the Alaska Assets in August 2007. Oil and natural gas revenues before hedging effects in 2007 were $1.1 billion, a 26% increase as compared to $858.3 million in 2006. The increase in oil and natural gas revenues before hedging effects of $224.8 million was due to the 28% increase in production, offset by a 2% decrease in the average realized sales price (before the effects of hedging), to $6.96 per Mcfe in 2007 from $7.08 per Mcfe in 2006.

Net oil and gas production in 2006 was 121.2 Bcfe or an average of 332.0 MMcfe per day, a 27% decrease from 165.2 Bcfe or an average of 452.7 MMcfe per day in 2005. The net decrease in oil and gas production was primarily attributable to the spin-off of our offshore Gulf of Mexico properties on March 2, 2006, partially offset by production increases in the Buffalo Wallow area and the Canadian Deep Basin as well as the East Texas property acquisition in March 2006. Oil and natural gas revenues before hedging effects were $858.3 million in 2006, a 31% decrease as compared to $1.2 billion in 2005. The decrease in oil and natural gas revenues before hedging effects was due to the 27% decrease in production as well as a 6% decrease in the average realized sales price (before the effects of hedging) to $7.08 per Mcfe in 2006 from $7.56 in 2005.

Hedge Effects

The table above also presents the effects of the derivative instruments (e.g., commodity swaps and collars) we designated as cash flow hedges. Beginning in March 2006, we elected to discontinue the use of cash flow hedge accounting for all of our commodity derivatives. Accordingly, all gains or losses recognized (i.e., cash settlements) in connection with hedging activities for the majority of 2006 and all of 2007 are reflected in "Realized gains and losses on derivative instruments" in other income and expense in our Consolidated Statements of Operations rather than being included as part of "Revenues". 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, 2007, 2006, and 2005:

	Year Ended December 31,		
	2007	**2006**	**2005**
	(In Thousands, Except per Mcfe Data)		
Lease operating expenses ("LOE"):			
Direct operating expense and overhead	$146,868	132,568	166,119
Workover expense	20,605	22,130	30,011
Hurricane repairs	—	176	3,631
Total LOE	$167,473	154,874	199,761
LOE per Mcfe	$ 1.08	1.28	1.21
Production and property taxes	$ 55,264	39,041	42,615
Production and property taxes per Mcfe	$ .35	.32	.26
Transportation and processing costs	$ 20,200	21,876	19,499
Transportation and processing costs per Mcfe	$ .13	.18	.12
Total oil and gas production expense	$242,937	215,791	261,875
Total oil and gas production expense per Mcfe	$ 1.56	1.78	1.58

Lease Operating Expenses

Lease operating expenses were $167.5 million in 2007, an increase of 8% compared to $154.9 million in 2006. On a per-Mcfe basis, LOE decreased 16% to $1.08 per Mcfe in 2007 from $1.28 per Mcfe in 2006. The decrease in LOE on a per-Mcfe basis is primarily due to lower average per-unit lease operating expenses from the assets acquired from Houston Exploration in June 2007, the divestiture of the Alaska Assets in August 2007, and continued cost reduction initiatives. Lease operating expenses decreased 22%, or $44.9 million, to $154.9 million in 2006 from $199.8 million in 2005. The decrease in lease operating expenses is primarily due to the spin-off of our Gulf of Mexico operations on March 2, 2006, partially offset by increases in operating expenses associated with our acquisition of East Texas properties in March 2006. On a per-Mcfe basis, LOE increased to $1.28 per Mcfe in 2006 from $1.21 per Mcfe in 2005.

Production and Property Taxes

Production and property taxes, which are primarily made up of severance taxes paid on the value of the oil and gas produced, generally fluctuate proportionately to our oil and gas revenues. As a percentage of oil and natural gas revenue, excluding hedging losses recognized in 2006 and 2005, production and property taxes were 5.1%, 4.5%, and 3.4% for the years ended December 31, 2007, 2006, and 2005, respectively. The increase in each period is primarily the result of a change in our production mix to a higher percentage of onshore production, which is generally subject to production taxes, versus offshore Gulf of Mexico production, which is generally not subject to production taxes. In addition, normal fluctuations will occur between periods based on the approval of incentive tax credits, changes in tax rates, and changes in the assessed values of property and equipment for purposes of ad valorem taxes.

Transportation and Processing Costs

Transportation and processing costs were $20.2 million, or $.13 per Mcfe, in 2007 compared to $21.9 million, or $.18 per Mcfe, in 2006. The decrease of $.05 on a per-Mcfe basis in 2007 was due primarily to lower per-unit transportation costs incurred in Alaska in 2007 compared to the prior year and due to the sale of the Alaska Assets in August 2007. Transportation and processing costs were $21.9 million, or $.18 per Mcfe, in 2006 compared to $19.5 million, or $.12 per Mcfe, in 2005. The $.06 per Mcfe increase was primarily due to higher transportation and processing costs in Canada and due to lower average per-unit transportation and processing costs associated with our offshore Gulf of Mexico operations, which were included in the Spin-off in March 2006.

General and Administrative Expense

The following table summarizes the components of general and administrative expense incurred during the periods indicated:

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands, Except Per Mcfe Data)		
Stock-based compensation costs	$ 17,681	22,048	1,275
Other general and administrative costs	89,697	58,108	68,934
General and administrative costs capitalized	(43,627)	(31,848)	(26,506)
General and administrative expense	$ 63,751	48,308	43,703
General and administrative expense per Mcfe	$ .41	.40	.26

General and administrative expense increased $15.5 million to $63.8 million in 2007 from $48.3 million in 2006. The increase in net general and administrative expense was primarily related to increased employee salary and benefit costs resulting from the acquisition of Houston Exploration, offset by a reduction to stock-based compensation costs in 2007. The increase in general and administrative expense of $4.6 million to $48.3 million in 2006 from $43.7 million in 2005 was primarily related to higher stock-based compensation costs (discussed below), offset by salary and benefit savings related to a reduction in the number of employees subsequent to the Spin-off. The increase of $.14 on a per-unit basis from 2005 to 2006 was also primarily due to stock-based compensation costs. The percentage of general and administrative costs capitalized remained relatively constant between the three years, ranging between 38% and 41%.

The increase in stock-based compensation costs beginning in 2006 was due to the implementation of Statement of Financial Accounting Standards ("SFAS") No. 123 (Revised), "*Share-Based Payment*" ("SFAS 123(R)"). 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), we recorded stock-based compensation cost in the amount of $17.7 million in 2007 and $22.0 million in 2006, of which approximately $9.7 million was attributed to a partial settlement of Forest's restricted stock awards and phantom stock unit awards in connection with the Spin-off. The decrease in stock-based compensation of $4.3 million in 2007 from 2006 was due to the $9.7 million partial settlement in 2006, partially offset by the recognition of stock-based compensation associated with restricted stock and stock options granted in 2007.

Depreciation and Depletion; Undeveloped Properties

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands, Except Per Mcfe Amounts)		
Depreciation and depletion expense	$390,338	266,881	368,679
Depreciation and depletion expense per Mcfe	$ 2.51	2.20	2.23

Depreciation, depletion, and amortization expense ("DD&A") in 2007 was $390.3 million compared to $266.9 million in 2006. On an equivalent Mcf basis, DD&A expense increased to $2.51 per Mcfe in 2007 compared to $2.20 per Mcfe in 2006. The increase of $.31 per Mcfe in 2007 was primarily due to the acquisition of the Houston Exploration properties, which had higher-than-historical per-unit depletion rates. DD&A in 2006 was $266.9 million compared to $368.7 million in 2005.

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

December 31,	United States	Canada	International	Total
		(In Thousands)		
2007	$445,949	63,951	58,610	568,510
2006	149,687	53,034	58,538	261,259
2005	174,249	44,798	56,637	275,684

The increase in the total undeveloped properties of $307.3 million in 2007 from $261.3 million in 2006 is primarily attributable to the Houston Exploration acquisition completed in 2007. The decrease in the total undeveloped properties of $14.4 million in 2006 from $275.7 million in 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. See Note 2 to the Consolidated Financial Statements for additional information on acquisitions and divestitures.

Accretion of Asset Retirement Obligations

Accretion expense of $6.1 million in 2007, $7.1 million in 2006, and $17.3 million in 2005 was related to the accretion of Forest's asset retirement obligations pursuant to SFAS No. 143, *"Accounting for Asset Retirement Obligations"*. 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. Subsequent to initial measurement, the asset retirement obligation is required to be accreted each period to its present value. The significant decrease from 2005 to 2006 is attributable to the large reduction in future abandonment liabilities associated with the Spin-off in March 2006, discussed above. See Note 1 to the Consolidated Financial Statements for additional information on our asset retirement obligations.

International Impairments

Forest recorded impairments related to its international properties of $3.7 million in 2006, with $2.1 million 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.

Gain on Sale of Assets

During the year ended December 31, 2007, Forest sold overriding royalty interests in Australia for net proceeds of $7.2 million that resulted in a gain on the sale of $7.2 million.

Interest Expense

Interest expense of $113.2 million in 2007 increased by $41.4 million, or 58%, from $71.8 million in 2006. The increase in interest expense in 2007 from 2006 is primarily due to the 7¼% senior notes due 2019 that we issued in June 2007 and the Alaska term loan credit facilities, which were entered into in December 2006 and were paid off in August 2007. 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 costs related to significant unproved properties that are under development are capitalized to oil and gas properties under the full cost method of accounting. Forest capitalized interest of $13.9 million, $3.7 million, and $.9 million during the years ended December 31, 2007, 2006, and 2005, respectively. The increase in interest capitalized in 2007 from 2006 is due to the acquisition of Houston Exploration, which included a large investment in unproved properties.

Realized and Unrealized Gains and Losses on Derivative Instruments

The table below sets forth realized and unrealized gains and losses on derivatives recognized under "Other income and expense" in our Consolidated Statements of Operations for the periods indicated. Since March 2006, when Forest elected to discontinue cash flow hedge accounting for all of its derivative instruments, Forest has recognized all mark-to-market gains and losses as "Unrealized gains and losses on derivative instruments" in other income and expense in the Consolidated Statements of Operations rather than deferring any such amounts in "Accumulated other comprehensive income" in shareholders' equity. In addition, cash settlements on derivative instruments are recorded as "Realized gains and losses on derivative instruments" in other income and expense in the Consolidated Statements of Operations rather than as an adjustment to "Revenues" or "Interest expense." The amounts shown in the table below for 2006 and 2005, prior to our discontinuance of cash flow hedge accounting, represent amounts related to ineffective hedges or derivatives that did not meet the criteria to qualify for cash flow hedge accounting. See Note 9 to the Consolidated Financial Statements for more information on our derivative instruments.

	Year Ended December, 31		
	2007	2006	2005
	(In Thousands)		
Realized (gains) and losses on derivatives, net:			
Oil[(1)]	$ (2,587)	29,743	(527)
Gas	(72,904)	(5,879)	35,917
Interest	(474)	—	—
Total	$ (75,965)	23,864	35,390
Unrealized losses (gains) on derivatives, net:			
Oil	$123,099	(36,953)	3,475
Gas	(10,321)	(46,676)	17,898
Interest	4,721	—	—
Total	$117,499	(83,629)	21,373

(1) Includes total proceeds of $6.9 million for two oil swap agreements that we unwound in 2007, which covered 1,000 Bbl per day in 2009 and 500 Bbl per day in 2010.

Other Income and Expense

The components of other income and expense for the years ended December 31, 2007, 2006, and 2005 were as follows:

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands)		
Realized foreign currency exchange gains	$ (7,721)	(315)	—
Unrealized foreign currency exchange (gain) loss	(7,694)	3,931	—
Franchise taxes	2,322	1,410	1,963
Share of (income) loss of equity method investee	(275)	(2,334)	562
Unrealized loss on other investments	4,948	—	—
Debt extinguishment costs	12,215	—	—
Other, net	(2,214)	1,135	3,722
Total other expense, net	$ 1,581	3,827	6,247

The realized foreign currency exchange gains relate to the repayments of intercompany debt owed to Forest Oil Corporation by our Canadian subsidiary. The unrealized foreign currency exchange gains and losses relate to the outstanding intercompany indebtedness between Forest Oil Corporation and our Canadian subsidiary. 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 related to our 40% ownership of a pipeline company that transports crude oil in Alaska, which was included in the sale of the Alaska Assets in August 2007. The unrealized loss on other investments relates to the mark-to-market adjustment of the PERL common stock we received as a portion of the consideration in the sale of the Alaska Assets in August 2007. Debt extinguishment costs related to the complete repayment of the Alaska credit agreements and include $5.0 million in prepayment premiums and $7.2 million of unamortized debt issue costs.

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,		
	2007	2006	2005
	(In Thousands, Except Percentages)		
Current income tax expense	$ 5,999	2,126	3,498
Deferred income tax expense	56,396	88,777	89,860
Total income tax expense	$62,395	90,903	93,358
Effective tax rate	27%	35%	38%

The increase in our current income tax expense in 2007 is primarily due to the sale of our Alaska Assets, which increased our income subject to federal alternative minimum tax and the implementation of a margin tax by the state of Texas effective January 1, 2007. The decrease in our effective tax rate in 2007 to 27%, from 35% in 2006, was primarily due to a reduction in income taxes of approximately $21.0 million related to statutory rate reductions enacted in Canada, release of valuation allowances, and a lower apportioned effective state income tax rate. 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 also related to statutory rate reductions enacted in Canada as well as changes in the Texas income tax law, both offset in part by an increase 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. The subsidiary's results of operations have been reported as discontinued operations in the Consolidated Statements of Operations for all years presented. 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 two years if Cinergy meets certain earnings goals with respect to the acquired business. During the years ended December 31, 2007 and 2005, Forest did not receive any additional contingent payments. During 2006, Forest received an additional $3.6 million contingent payment ($2.4 million net of tax) under the agreement, which has been reflected as income from discontinued operations in the Consolidated Statements of Operations.

Liquidity and Capital Resources

In 2008, as in 2007, 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 senior notes that will come due in June 2008.

The prices we receive for our oil and natural gas production have a significant impact on operating cash flows. While significant price declines in 2008 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, 2008, Forest has hedged approximately 75 Bcfe of its 2008 production. This level of hedging provides some certainty of the cash flow we will receive for a portion of our expected 2008 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 2008 hedging contracts, see Item 7A—"Quantitative and Qualitative Disclosures about Market Risk—*Hedging Program*," below.

Our revolving U.S. and Canadian bank credit facilities, which were amended and restated in June 2007, provide another source of liquidity. These credit facilities, which mature in June 2012, are used to fund daily operating activities and acquisitions in the United States and Canada as needed. See "*Bank Credit Facilities*" below for details.

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. Nevertheless, ready access to capital on reasonable terms can be impacted by our debt ratings assigned by independent rating agencies and are subject to many uncertainties, including restrictions contained in our bank credit facilities and indentures for our senior notes, macroeconomic factors outside of our control, and other risks as explained in Part 1, Item 1A—"Risk Factors."

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

Bank Credit Facilities

On June 6, 2007, Forest entered into amended and restated credit facilities totaling $1.0 billion. The amended and restated facilities consist of an $850 million U.S. credit facility (the "U.S. Facility") through a syndicate of banks led by JPMorgan Chase Bank, N.A. and a $150 million Canadian credit facility (the "Canadian Facility", and together with the U.S. Facility, the "Credit Facilities") through a syndicate of banks led by JPMorgan Chase Bank, N.A., Toronto Branch. The Credit Facilities mature in June 2012. Subject to the agreement of Forest and the applicable lenders, the size of the Credit Facilities may be increased by $800 million in the aggregate.

Forest's availability under the Credit Facilities will be governed by a borrowing base ("Global Borrowing Base") which currently is set at $1.4 billion, with $1.25 billion allocated to the U.S. credit facility and $150 million allocated to the Canadian credit facility. The determination of the Global Borrowing Base is made by the lenders in their sole discretion 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. The Global Borrowing Base 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.

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, and include financial covenants. Interest rates and collateral requirements under the Credit Facilities will vary based on Forest's credit ratings and financial condition, as governed by certain financial tests.

Under certain conditions, amounts outstanding under the Credit Facilities may be accelerated. Bankruptcy and insolvency events with respect to Forest or certain of its subsidiaries will result in an automatic acceleration of the indebtedness under the Credit Facilities. Subject to notice and cure periods in certain cases, other events of default under either of the Credit Facilities will result in acceleration of the indebtedness under the facilities at the option of the lenders. Such other events of default include non-payment, breach of warranty, non-performance of obligations under the Credit Facilities (including financial covenants), default on other indebtedness, certain pension plan events, certain adverse judgments, change of control, a failure of the liens securing the Credit Facilities, and an event of default under the Canadian Facility.

The Credit Facilities include provisions and conditions linked to Forest's credit ratings. Forest's ability to raise funds and the cost of any financing activities may be affected by our credit ratings at the time any such activities are conducted. See Note 4 to the Consolidated Financial Statements for more information on the Credit Facilities.

The Credit Facilities are collateralized by a portion of Forest's assets. We are required to mortgage, and grant a security interest in, 75% of the present value of our consolidated proved oil and gas properties. We 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 Forest's 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.

From time to time, Forest and the syndication agents, documentation agents, global administrative agent, and the other lenders party to the Credit Facilities engage in other transactions, including securities offerings where such parties or their affiliates may serve as an underwriter or initial purchaser of Forest's securities and, or serve as counterparties to Forest's derivative agreements.

At December 31, 2007, there were outstanding borrowings of $165.0 million under the U.S. Facility at a weighted average interest rate of 6.2%, and there were outstanding borrowings of $129.1 million under the Canadian Facility at a weighted average interest rate of 5.9%. We also had used the Credit Facilities for approximately $2.6 million in letters of credit, leaving an unused borrowing amount under the Credit Facilities of approximately $703.3 million at December 31, 2007. At January 31, 2008, there were outstanding borrowings of $192.0 million under the U.S. Facility at a weighted average interest rate of 5.6%, and there were outstanding borrowings of $116.6 million under the Canadian Facility at a weighted average interest rate of 5.6%. We also had used the Credit Facilities for approximately $2.6 million in letters of credit, leaving an unused borrowing amount under the Credit Facilities of approximately $688.8 million at January 31, 2008.

Alaska Credit Agreements

On December 8, 2006, Forest, through its wholly-owned subsidiaries, Forest Alaska Operating LLC and Forest Alaska Holding LLC (together "Forest Alaska"), 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 "Alaska 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.

During the year ended December 31, 2007, Forest Alaska made scheduled repayments of $1.3 million and a voluntary prepayment of $110.0 million on the first lien credit agreement. In conjunction with the sale of the Alaska Assets on August 27, 2007, Forest used a portion of the $400 million cash consideration to repay the remaining $263.7 million principal balance outstanding under the Alaska Credit Agreements. During the year ended December 31, 2007, Forest recognized debt extinguishment costs of $12.2 million associated with payments on the Alaska Credit Agreements. The debt extinguishment costs included $5.0 million in prepayment premiums on the Alaska Credit Agreements and $7.2 million of unamortized debt issuance costs.

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.

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, 2007, 2006, and 2005 were as follows:

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands)		
Net cash provided by operating activities	$ 708,245	422,478	628,565
Net cash used by investing activities	(1,093,221)	(909,891)	(671,230)
Net cash provided (used) by financing activities	359,552	513,832	(4,596)

The increase in net cash provided by operating activities of $285.8 million in 2007 as compared to 2006 was primarily due to higher net income before non-cash charges and a decreased investment in net operating assets in 2007 as compared to 2006. 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 in March 2006.

Cash used by investing activities increased in 2007 by $183.3 million as compared to 2006 primarily due to an increase in cash used for acquisitions, exploration, and development of oil and gas properties, offset by an increase in proceeds from the sale of oil and gas properties. The increase in cash used by investing activities in 2006 of $238.7 million compared to 2005 was also primarily due to an increase in cash used for the acquisition, exploration, and development of oil and gas properties. The major components of cash used by investing activities for the years ended December 31, 2007, 2006 and 2005 were as follows:

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands)		
Acquisitions	$ (778,880)	(292,807)	(204,450)
Exploration and development costs	(784,220)	(601,641)	(475,524)
Other fixed assets	(32,169)	(21,950)	(10,743)
Proceeds from sale of Alaska Assets	400,000	—	—
Proceeds from sale of other assets	102,048	6,507	24,046
Other	—	—	(4,559)
Net cash used by investing activities	$(1,093,221)	(909,891)	(671,230)

Net cash provided by financing activities of $359.6 million in 2007 included the issuance of the 7¼% Notes for net proceeds of $739.2 million, net bank proceeds of $171.3 million, and proceeds from the exercise of stock options and from the employee stock purchase plan of $12.8 million, offset by the repayment of the Alaska Credit Agreements of $375.0 million and repayment of Houston Exploration's bank debt of $176.9 million. Net cash provided by financing activities in 2006 of $513.8 million included net bank proceeds of $130.2 million, proceeds from the Alaska Credit Agreements (net of issuance costs) of $367.7 million, $21.7 million of proceeds from the Spin-off, and proceeds from the exercise of stock options and from the employee stock purchase plan of approximately $6.8 million. Net cash used by financing activities in 2005 of $4.6 million primarily included the net repayment of bank borrowings of $33.3 million, more than offset by net proceeds from the exercise of options and warrants of approximately $43.4 million.

Capital Expenditures

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

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands)		
Property acquisitions:(1)			
Proved properties	$1,744,093	262,534	239,647
Undeveloped properties	449,346	53,788	73,868
	2,193,439	316,322	313,515
Exploration:			
Direct costs	137,475	250,344	247,331
Overhead capitalized	10,722	12,121	12,811
	148,197	262,465	260,142
Development:			
Direct costs	622,466	344,725	266,330
Overhead capitalized	32,905	19,727	13,695
	655,371	364,452	280,025
Total capital expenditures(1)(2)	$2,997,007	943,239	853,682

(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 $559.1 million in 2007 and $71.5 million in 2005 and exclude goodwill recorded in connection with business combinations of approximately $176.8 million in 2007 and $23.0 million in 2005. See Note 2 to the Consolidated Financial Statements for the allocation of purchase consideration for the larger acquisitions completed in 2007, 2006, and 2005.

(2) Includes estimated discounted asset retirement obligations of $37.8 million, $2.4 million, and $16.3 million related to assets placed in service during the years ended December 31, 2007, 2006, and 2005, respectively.

Forest's anticipated expenditures for exploration and development in 2008 are estimated to range from $900 million to $1 billion. Some of the factors impacting the level of capital expenditures in 2008 include crude oil and natural gas prices, the volatility in these prices, the cost and availability of oil field services, general economic and market conditions, and weather disruptions.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2007:

	2008	2009	2010	2011	2012	After 2012	Total
			(In Thousands)				
Bank debt(1)	$ 17,892	17,892	17,892	17,892	303,073	—	374,641
Senior notes(2)	364,808	89,208	89,208	374,208	66,204	1,275,167	2,258,803
Operating leases(3)	18,113	16,643	14,499	14,364	13,496	27,449	104,564
Unconditional purchase obligations(4)	42,881	27,099	1,607	513	123	—	72,223
Other liabilities(5)	6,580	8,950	8,970	11,439	10,500	82,454	128,893
Derivative liabilities(6)	72,675	30,545	7,626	—	—	—	110,846
Approved capital projects(7)	52,903	—	—	—	—	—	52,903
Total contractual obligations	$575,852	190,337	139,802	418,416	393,396	1,385,070	3,102,873

(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 interest rates in effect at December 31, 2007.

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

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

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

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

(6) Derivative liabilities represent the fair value of liabilities for oil and gas commodity and interest rate derivatives as of December 31, 2007. The ultimate settlement amounts of our derivative liabilities are unknown, because they are subject to continuing market risk. See "Critical Accounting Policies, Estimates, Judgments, and Assumptions," below for a more detailed discussion of the nature of the accounting estimates involved in valuing derivative instruments.

(7) Consists of our net share of budgeted expenditures under Authorizations for Expenditure ("AFE") that were approved by us and our joint venture partners as of December 31, 2007. Includes AFEs for which Forest is the operator as well as those operated by others.

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 2015 totaled approximately $1.2 million as of December 31, 2007.

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, 2007, 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 gas transportation commitments and derivative contracts that are sensitive to future changes in commodity prices and interest rates. Forest does not believe that any of these arrangements are reasonably likely to materially affect its liquidity or availability of, or requirements for, capital resources.

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, 2008, 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 $19.6 million. See Part I, Item 1—"Business—Regulation" for further information.

Critical Accounting Policies, Estimates, Judgments, and Assumptions

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. Impairments are also 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.

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 16 to the Consolidated Financial Statements.

Reference should be made to "*Independent Audit of Reserves*" under Part I, Item 1—"Business," and "*Our proved reserves are estimates and depend on many assumptions. Any material inaccuracies in these assumptions could cause the quantity and value of our oil and gas reserves, and our revenue, profitability, and cash flow, to be materially different from our estimate*", under Part I, Item 1A—"Risk Factors," in this Form 10-K.

Accounting for Derivative Instruments

We follow 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, we 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. 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. Since March 2006, we have elected not to use hedge accounting. Accordingly, after March 2006, all changes in the fair values of our derivative instruments have been and will continue to be recognized in earnings as "Unrealized gains or losses on derivative instruments" in our Consolidated Statements of Operations.

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 estimated fair values of our commodity derivative instruments are subject to large fluctuations from period to period. For example, a hypothetical 10% increase in the forward oil and natural gas prices used to calculate the fair values of our commodity derivative instruments at December 31, 2007 would decrease the net fair value of our commodity derivative instruments at December 31, 2007 by approximately $78 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 related to our commodity derivative instruments will likely differ from those estimated at December 31, 2007 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 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, 2007. 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. 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 Statements of Operations.

Impact of Recently Issued Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, *"Fair Value Measurements"* ("SFAS 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 157 is effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position ("FSP") No. 157-1 and FSP No. 157-2. FSP No. 157-1 amends SFAS 157 to exclude lease transactions accounted for under SFAS No. 13, *"Accounting for Leases"* ("SFAS 13") and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. This scope exception does not apply to assets acquired and liabilities assumed in a business combination that are required to be measured at fair value under SFAS No. 141, *"Business Combinations"* or SFAS 141(R), regardless of whether those assets and liabilities are related to leases. FSP No. 157-2 delays the effective date of SFAS 157 for one year for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We are currently evaluating the impact the adoption of these pronouncements will have on our financial position and results of operations.

In September 2006, the FASB ratified the consensus reached by the Emerging Issues Task Force ("EITF") related to EITF Issue No. 06-4, "*Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements"* ("EITF 06-4"), which requires the recognition of a liability for future benefits based on the substantive agreement with the employee. The liability is required to be recognized in accordance with SFAS No. 106, *"Employers' Accounting for Postretirement Benefits Other Than Pensions"* ("SFAS 106"), or APB Opinion No. 12, *"Omnibus Opinion—1967"*, as appropriate. EITF 06-4 is effective for fiscal years beginning after December 15, 2007 and requires transition through a cumulative effect adjustment to retained earnings or a retrospective application to all prior periods. We maintain a number of split-dollar life insurance arrangements for certain former employees. We are currently evaluating the impact the adoption of this pronouncement will have on our financial position and results of operations.

In February 2007, the FASB issued SFAS 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 for fiscal years beginning after November 15, 2007. We do not expect the adoption of this pronouncement to have a material impact on our financial position or results of operations.

In March 2007, the FASB ratified the consensus reached by the EITF in Issue No. 06-10, "*Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements"* ("EITF 06-10"). Under this consensus, an employer should recognize a liability for any postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 or APB Opinion No. 12, as appropriate, and should recognize and measure the underlying asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 is effective for fiscal years beginning after December 15, 2007 and requires transition through a cumulative effect adjustment to retained earnings or a retrospective application to all prior periods. We maintain a number of split-dollar life insurance arrangements for certain former employees. We are currently evaluating the impact the adoption of this pronouncement will have on our financial position and results of operations.

In December 2007, the FASB issued SFAS No. 141 (Revised), *"Business Combinations"* ("SFAS 141(R)"), which significantly changes the financial accounting and reporting of business combination transactions. SFAS 141(R) establishes principles and requirements for how an acquirer in a business combination: (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The adoption of this pronouncement may have a material impact on the accounting for any acquisitions we may make after January 1, 2009.

In December 2007, the FASB issued SFAS No. 160, *"Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51"* ("SFAS 160"). This statement amends ARB No. 51 to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. This statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. We do not expect the adoption of this pronouncement to have a material impact 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 commodity prices, 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, 2007, we had entered into the following swaps:

	Swaps					
	Natural Gas (NYMEX HH)			Oil (NYMEX WTI)		
	Bbtu Per Day[1]	Weighted Average Hedged Price per MMBtu	Fair Value (In Thousands)	Barrels Per Day	Weighted Average Hedged Price per Bbl	Fair Value (In Thousands)
Calendar 2008	50	$8.38	$9,930	6,500	$69.72	$(54,592)
Calendar 2009	—	—	—	4,500	69.01	(28,563)
Calendar 2010	—	—	—	1,500	72.95	(6,951)

(1) 10 Bbtu per day is subject to a $6.00 written put.

Costless 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. As of December 31, 2007, we had entered into the following collars:

	Costless Collars[1]		
	Natural Gas (NYMEX HH)		
	Bbtu Per Day	Weighted Average Hedged Floor and Ceiling Price per MMBtu	Fair Value (In Thousands)
January – February 2008	130	$7.39/8.89	$ 1,138
March – December 2008	80	7.33/8.87	(1,385)

(1) Included in Forest's outstanding natural gas costless collars at December 31, 2007 are natural gas costless collars assumed in the Houston Exploration acquisition with a fair value of $(12.8) million. At December 31, 2007, these costless collars had weighted average hedged floor and ceiling prices per MMBtu of $7.20/8.51 for 100 Bbtu per day for January – February 2008, and $5.00/5.72 for 20 Bbtu per day for March – December 2008.

Three-Way Costless Collars

Forest also enters into three-way costless collars with third parties. These instruments establish two floors and one ceiling. Upon settlement, if the index price is below the lowest floor, Forest receives the difference between the two floors. If the index price is between the two floors, Forest receives the difference between the higher of the two floors and the index price. If the index price is between the higher floor and the ceiling, Forest does not receive or pay any amounts. If the index price is above the ceiling, Forest pays the excess over the ceiling price. As of December 31, 2007, we had entered into the following three-way collars:

	Three-Way Costless Collars		
	Natural Gas (NYMEX HH)		
	Bbtu Per Day	Weighted Average Hedged Lower Floor, Upper Floor, and Ceiling Price per MMBtu	Fair Value (In Thousands)
January – February 2008	20	$6.00/8.00/10.00	$ 903
March – December 2008	30	6.00/8.00/10.00	3,861

Basis Swaps

Forest also uses basis swaps in connection with natural gas swaps in order to fix the price differential between the NYMEX price and the index price at which the natural gas production is sold. As of December 31, 2007, we had entered into the following basis swaps:

	Basis Swaps[1]	
	Bbtu per Day	Fair Values (In Thousands)
Calendar 2008	80	$(460)

(1) Included in Forest's outstanding basis swaps at December 31, 2007 are basis swaps assumed in the Houston Exploration acquisition with a fair value of $.1 million. At December 31, 2007, these basis swaps are for 80 Bbtu per day for January – February 2008.

The fair value of all our commodity derivative instruments based on the futures prices quoted on December 31, 2007 was a net liability of approximately $76.1 million.

In January and February 2008, we entered into six additional gas swap agreements for 60 Bbtu per day at a weighted average hedged price per MMBtu of $8.99 for calendar 2009. In February 2008, we entered into an additional gas costless collar agreement for 20 Bbtu per day with a hedged floor and ceiling price per MMBtu of $8.00 and $10.56, respectively, for calendar 2009.

Fair Value Reconciliation

The following table reconciles the changes that occurred in the fair values of our open derivative contracts during the year ended December 31, 2007 (see discussion of interest rate swaps under "Interest Rate Risk" below):

	Fair Value of Derivative Contracts		
	Commodity	Interest Rate	Total
		(In Thousands)	
As of December 31, 2006	$ 66,119	—	66,119
Fair value of acquired derivatives	(45,170)	—	(45,170)
Settlements of acquired derivatives	15,710	—	15,710
Net decrease in fair value	(37,287)	(4,247)	(41,534)
Net contract gains recognized	(75,491)	(474)	(75,965)
As of December 31, 2007	$(76,119)	(4,721)	(80,840)

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, 2007:

	2008	2011	2012	2013	2014	2019	Total	Fair Value
	(Dollar Amounts in Thousands)							
Bank credit facilities:								
Variable rate	$ —	—	294,126	—	—	—	294,126	294,126
Average interest rate[1]	—	—	6.08%	—	—	—	6.08%	
Short-term debt:								
Fixed rate	$265,000	—	—	—	—	—	265,000	267,650
Coupon interest rate	8.00%	—	—	—	—	—	8.00%	
Effective interest rate[2]	7.13%	—	—	—	—	—	7.13%	
Long-term debt:								
Fixed rate	$ —	285,000	—	5,822	150,000	750,000	1,190,822	1,208,018
Coupon interest rate	—	8.00%	—	7.00%	7.75%	7.25%	7.49%	
Effective interest rate[2]	—	7.71%	—	7.00%	6.56%	7.25%	7.27%	

(1) As of December 31, 2007.

(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.

Interest Rate Swaps

Forest may enter into interest rate swap agreements in an attempt to normalize the mix of fixed and floating interest rates within its debt portfolio. Unrealized gains, losses, or any settlements are recorded in other income and expense in the Consolidated Statement of Operations. Pursuant to the requirements under the Alaska Credit Agreements, Forest Alaska entered into two floating to fixed interest rate swaps. In August 2007, Forest Alaska novated these interest rate swaps to Forest. Forest has maintained these interest rate swaps to fix a portion of its variable rate interest on its credit facility borrowings that are LIBOR based. As of December 31, 2007, we had entered into the following interest rate swaps:

	Term	Notional Amount	Floating Rate	Fixed Rate	Fair Value
	(Dollar Amounts in Thousands)				
Interest Rate Swap A	April 2007 – April 2010	$ 75,000	1 month LIBOR	4.80%	$(1,726)
Interest Rate Swap B	April 2007 – April 2010	112,500	1 month LIBOR	4.96%	(2,995)

In January 2008, we entered into a $100 million floating to fixed interest rate swap for three years commencing on June 13, 2008. The floating rate is one month LIBOR and the fixed rate is 2.75%.

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 sheets of Forest Oil Corporation and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for the years then ended. 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 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Forest Oil Corporation and subsidiaries at December 31, 2007 and 2006, and the consolidated results of their operations and their cash flows for the years then ended 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), Forest Oil Corporation's internal control over financial reporting as of December 31, 2007, 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, 2008 expressed an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
February 27, 2008

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Forest Oil Corporation:

We have audited the accompanying consolidated statements of operations, shareholders' equity, and cash flows of Forest Oil Corporation and subsidiaries for the year 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 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 consolidated financial statements referred to above present fairly, in all material respects, the results of the operations and cash flows of Forest Oil Corporation and subsidiaries for the year 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, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,685	33,164
Accounts receivable	201,617	125,446
Derivative instruments	30,006	53,205
Deferred income taxes	23,854	—
Other investments	34,694	—
Other current assets	61,518	49,185
Total current assets	361,374	261,000
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of $2,742,539 and $2,265,018	4,414,710	2,486,153
Unproved	568,510	261,259
Net oil and gas properties	4,983,220	2,747,412
Other property and equipment, net of accumulated depreciation and amortization of $30,011 and $32,504	42,595	42,514
Net property and equipment	5,025,815	2,789,926
Derivative instruments	—	15,019
Goodwill	265,618	86,246
Other assets	42,741	36,881
	$5,695,548	3,189,072
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 361,089	224,933
Accrued interest	7,693	6,235
Derivative instruments	72,675	1,294
Current portion of long-term debt	266,002	2,500
Asset retirement obligations	2,562	2,694
Deferred income taxes	—	14,907
Other current liabilities	28,361	11,378
Total current liabilities	738,382	263,941
Long-term debt	1,503,035	1,204,709
Asset retirement obligations	87,943	61,408
Derivative instruments	38,171	811
Deferred income taxes	853,427	191,957
Other liabilities	62,779	32,240
Total liabilities	3,283,737	1,755,066
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Preferred stock, none issued and outstanding	—	—
Common stock, 88,379,409 and 62,998,155 shares issued and outstanding	8,838	6,300
Capital surplus	1,966,569	1,215,660
Retained earnings	306,062	137,796
Accumulated other comprehensive income	130,342	74,250
Total shareholders' equity	2,411,811	1,434,006
	$5,695,548	3,189,072

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands, Except Per Share Amounts)		
Revenues	$1,083,892	819,992	1,072,045
Operating expenses:			
Lease operating expenses	167,473	154,874	199,761
Production and property taxes	55,264	39,041	42,615
Transportation and processing costs	20,200	21,876	19,499
General and administrative (including stock-based compensation)	63,751	48,308	43,703
Depreciation and depletion	390,338	266,881	368,679
Accretion of asset retirement obligations	6,064	7,096	17,317
Impairment and other	—	3,668	11,132
Gain on sale of assets	(7,176)	—	—
Spin-off costs	—	5,416	—
Total operating expenses	695,914	547,160	702,706
Earnings from operations	387,978	272,832	369,339
Other income and expense:			
Interest expense	113,162	71,787	61,403
Unrealized losses (gains) on derivative instruments, net	117,499	(83,629)	21,373
Realized (gains) losses on derivative instruments, net	(75,965)	23,864	35,390
Other expense, net	1,581	3,827	6,247
Total other income and expense	156,277	15,849	124,413
Earnings before income taxes and discontinued operations	231,701	256,983	244,926
Income tax expense:			
Current	5,999	2,126	3,498
Deferred	56,396	88,777	89,860
Total income tax expense	62,395	90,903	93,358
Earnings from continuing operations	169,306	166,080	151,568
Income from discontinued operations, net of tax	—	2,422	—
Net earnings	$ 169,306	168,502	151,568
Basic earnings per common share:			
Earnings from continuing operations	$ 2.22	2.67	2.47
Income from discontinued operations, net of tax	—	.04	—
Basic earnings per common share	$ 2.22	2.71	2.47
Diluted earnings per common share:			
Earnings from continuing operations	$ 2.18	2.62	2.41
Income from discontinued operations, net of tax	—	.04	—
Diluted earnings per common share	$ 2.18	2.66	2.41

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Capital Surplus	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Treasury Stock	Total Shareholders' Equity
				(In Thousands)			
Balances at January 1, 2005	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
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 SHAREHOLDERS' EQUITY (Continued)

	Common Stock		Capital Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
				(In Thousands)		
Balances at December 31, 2006	62,998	$6,300	1,215,660	137,796	74,250	1,434,006
Acquisition of Houston Exploration	23,990	2,399	724,013	—	—	726,412
Exercise of stock options	652	65	11,720	—	—	11,785
Employee stock purchase plan	33	3	1,057	—	—	1,060
Restricted stock issued, net of cancellations	736	74	(74)	—	—	—
Amortization of stock-based compensation	—	—	15,504	—	—	15,504
Adoption of FIN 48	—	—	—	(1,040)	—	(1,040)
Restricted stock redeemed and other	(30)	(3)	(1,311)	—	—	(1,314)
Comprehensive earnings:						
Net earnings	—	—	—	169,306	—	169,306
Decrease in unfunded postretirement benefits, net of tax	—	—	—	—	1,295	1,295
Foreign currency translation	—	—	—	—	54,797	54,797
Total comprehensive earnings						225,398
Balances at December 31, 2007	88,379	$8,838	1,966,569	306,062	130,342	2,411,811

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands)		
Operating activities:			
Net earnings	$ 169,306	168,502	151,568
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation and depletion	390,338	266,881	368,679
Unrealized losses (gains) on derivative instruments, net	117,499	(83,629)	21,373
Deferred income tax expense	56,396	90,004	89,860
Stock-based compensation expense	10,895	13,240	763
Accretion of asset retirement obligations	6,064	7,096	17,317
Impairments	—	3,668	2,924
Gain on sale of assets	(7,176)	—	—
Unrealized foreign currency exchange (gain) loss	(7,694)	3,931	—
Other, net	6,350	5,899	1,111
Changes in operating assets and liabilities, net of effects of acquisitions and divestitures:			
Accounts receivable	353	(640)	(15,350)
Other current assets	1,557	(39,860)	(25,858)
Accounts payable	(9,592)	9,200	9,528
Accrued interest and other current liabilities	(26,051)	(21,814)	6,650
Net cash provided by operating activities	708,245	422,478	628,565
Investing activities:			
Capital expenditures for property and equipment:			
Acquisition of Houston Exploration, net of cash acquired (Note 2)	(775,365)	—	—
Exploration, development, and other acquisition costs	(787,735)	(894,448)	(679,974)
Other fixed assets	(32,169)	(21,950)	(10,743)
Proceeds from sale of Alaska Assets (Note 2)	400,000	—	—
Proceeds from sales of other assets	102,048	6,507	24,046
Other, net	—	—	(4,559)
Net cash used by investing activities	(1,093,221)	(909,891)	(671,230)
Financing activities:			
Proceeds from bank borrowings	1,536,526	1,562,778	906,741
Repayments of bank borrowings	(1,365,178)	(1,432,574)	(905,000)
Issuance of 7¼% senior notes, net of issuance costs	739,176	—	—
Repayment of Alaska Credit Agreements	(375,000)	—	—
Repayments of bank debt assumed in acquisitions	(176,885)	—	(35,000)
Proceeds from Alaska Credit Agreements, net of issuance costs	—	367,706	—
Proceeds from Spin-off	—	21,670	—
Proceeds from the exercise of options and warrants and from employee stock purchase plan	12,845	6,811	43,377
Other, net	(11,932)	(12,559)	(14,714)
Net cash provided (used) by financing activities	359,552	513,832	(4,596)
Effect of exchange rate changes on cash	1,945	(486)	(759)
Net (decrease) increase in cash and cash equivalents	(23,479)	25,933	(48,020)
Cash and cash equivalents at beginning of year	33,164	7,231	55,251
Cash and cash equivalents at end of year	$ 9,685	33,164	7,231
Cash paid during the year for:			
Interest	$ 125,276	76,979	66,140
Income taxes	6,445	5,590	7,900

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2007, 2006, and 2005

(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 and development 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 2007 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 highly liquid investments with original maturities of three months or less to be cash equivalents.

Property and Equipment

The Company uses the full cost method of accounting for oil and gas properties. Separate cost centers are maintained for each country in which the Company has operations. During 2007, 2006, and 2005, the Company's primary oil and gas operations were conducted in the United States and Canada.

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

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, 2007, 2006, and 2005, Forest capitalized $43.6 million, $31.8 million, and $26.5 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 2007, 2006, and 2005, the Company capitalized approximately $13.9 million, $3.7 million, and $.9 million, respectively, of interest expense attributed to unproved properties.

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, at 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 2007, 2006, or 2005.

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.

Asset Retirement Obligations

Forest records estimated future asset retirement obligations pursuant to the provisions of Statement of Financial Accounting Standards (“SFAS”) No. 143, “*Accounting for Asset Retirement Obligations”* (“SFAS No. 143”). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. Subsequent to initial measurement, the asset retirement obligation 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, 2007 and 2006:

	Year Ended December 31,	
	2007	2006
	(In Thousands)	
Asset retirement obligations at beginning of period	$ 64,102	211,554
Accretion expense	6,064	7,096
Liabilities incurred	5,195	3,033
Liabilities settled	(2,512)	(6,652)
Disposition of properties	(17,476)	(150,182)
Liabilities assumed	36,424	1,009
Revisions of estimated liabilities	(3,843)	(1,687)
Impact of foreign currency exchange rate	2,551	(69)
Asset retirement obligations at end of period	90,505	64,102
Less: current asset retirement obligations	(2,562)	(2,694)
Long-term asset retirement obligations	$ 87,943	61,408

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.

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, senior subordinated notes, and Alaska credit agreements were estimated based on quoted market prices, if available, or quoted

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

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, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In Thousands)			
8% Senior Notes due 2008	$266,002	267,650	268,200	271,294
8% Senior Notes due 2011	293,482	296,400	295,610	296,400
7% Senior Subordinated Notes due 2013	5,664	5,618	—	—
7¾% Senior Notes due 2014	159,763	152,250	161,305	152,625
7¼% Senior Notes due 2019	750,000	753,750	—	—
Alaska Credit Agreement—first lien	—	—	250,000	251,250
Alaska Credit Agreement—second lien	—	—	125,000	130,000

Revenues

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, 2007 and 2006, the Company had gas imbalance payables of $8.4 million and $5.6 million, respectively, and gas imbalance receivables of $9.2 million and $5.1 million, respectively.

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

In 2007 and 2005, there were no purchasers who exceeded 10% of total revenue. In 2006, sales to two purchasers were approximately 13% and 12% of total revenue.

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.

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

Accounts Receivable

The components of accounts receivable include the following:

	December 31, 2007	December 31, 2006
	(In Thousands)	
Oil and gas sales	$150,258	89,082
Joint interest billings	44,810	27,891
Other	7,011	8,814
Allowance for doubtful accounts	(462)	(341)
Total accounts receivable	$201,617	125,446

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 2007 and 2006, Forest realized approximately $7.7 million and $.3 million, respectively, of foreign currency exchange gains in connection with the repayment of intercompany debt owed to the Forest Oil Corporation by Canadian Forest.

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

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

units, and warrants. The following sets forth the calculation of basic and diluted earnings per share for the periods presented:

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands, Except Per Share Amounts)		
Earnings from continuing operations	$169,306	166,080	151,568
Income from discontinued operations, net of tax	—	2,422	—
Net earnings	$169,306	168,502	151,568
Weighted average common shares outstanding during the period	76,101	62,226	61,405
Add dilutive effects of stock options, unvested restricted stock grants, and unvested phantom stock units	1,650	1,205	1,145
Add dilutive effects of warrants	—	—	328
Weighted average common shares outstanding during the period, including the effects of dilutive securities	77,751	63,431	62,878
Basic earnings per common share:			
From continuing operations	$ 2.22	2.67	2.47
From discontinued operations	—	.04	—
Basic earnings per common share	$ 2.22	2.71	2.47
Diluted earnings per common share:			
From continuing operations	$ 2.18	2.62	2.41
From discontinued operations	—	.04	—
Diluted earnings per common share	$ 2.18	2.66	2.41

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 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 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 and our revolving bank credit facilities. The remaining unamortized debt issue costs at December 31, 2007 and 2006 totaled $19.7 million and $13.0 million, respectively, and are being amortized over the life of the respective debt instruments. The increase in 2007 includes the debt issue costs associated with the issuance of the $750 million 7¼% senior notes due 2019, in June 2007.

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 and liquids prices could lead to an impairment of goodwill in future periods.

A portion of our goodwill is assigned to the Canadian geographical business segment and normal fluctuations will occur between periods based upon changes in foreign currency exchange rates. During the year ended December 31, 2007, Forest recognized $176.8 million of goodwill associated with the Houston Exploration acquisition, as discussed in Note 2.

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.

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

The components of accumulated other comprehensive earnings (loss) for the years ended December 31, 2007, 2006, and 2005 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, 2005	$ 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
2007 activity	54,797	1,295	—	56,092
Balance at December 31, 2007	$135,344	(5,002)	—	130,342

(1) Net of tax.

Impact of Recently Issued Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, *"Fair Value Measurements"* ("SFAS 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 157 is effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position ("FSP") No. 157-1 and FSP No. 157-2. FSP No. 157-1 amends SFAS 157 to exclude lease transactions accounted for under SFAS No. 13, *"Accounting for Leases"* ("SFAS 13") and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. This scope exception does not apply to assets acquired and liabilities assumed in a business combination that are required to be measured at fair value under SFAS No. 141, *"Business Combinations"* or SFAS 141(R), regardless of whether those assets and liabilities are related to leases. FSP No. 157-2 delays the effective date of SFAS 157 for one year for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The Company is currently evaluating the impact the adoption of these pronouncements will have on the Company's financial position and results of operations.

In September 2006, the FASB ratified the consensus reached by the Emerging Issues Task Force ("EITF") related to EITF Issue No. 06-4, *"Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements"* ("EITF 06-4"), which requires the recognition of a liability for future benefits based on the substantive agreement with the employee. The liability is required to be recognized in accordance with SFAS No. 106, *"Employers' Accounting for Postretirement Benefits Other Than Pensions"* ("SFAS 106"), or APB Opinion No. 12, *"Omnibus Opinion—1967"*, as appropriate. EITF 06-4 is effective for fiscal years beginning after December 15, 2007 and requires transition through a cumulative effect adjustment to retained earnings or a retrospective application to all prior periods. The Company maintains a number of split-dollar life insurance arrangements for certain former employees. The Company is currently evaluating the impact the adoption of this pronouncement will have on the Company's financial position and results of operations.

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

In February 2007, the FASB issued SFAS 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 for fiscal years beginning after November 15, 2007. The Company does not expect the adoption of this pronouncement to have a material impact on the Company's financial position or results of operations.

In March 2007, the FASB ratified the consensus reached by the EITF in Issue No. 06-10, "*Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements"* ("EITF 06-10"). Under this consensus, an employer should recognize a liability for any postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 or APB Opinion No. 12, as appropriate, and should recognize and measure the underlying asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 is effective for fiscal years beginning after December 15, 2007 and requires transition through a cumulative effect adjustment to retained earnings or a retrospective application to all prior periods. The Company maintains a number of split-dollar life insurance arrangements for certain former employees. The Company is currently evaluating the impact the adoption of this pronouncement will have on the Company's financial position and results of operations.

In December 2007, the FASB issued SFAS No. 141 (Revised), *"Business Combinations"* ("SFAS 141(R)"), which significantly changes the financial accounting and reporting of business combination transactions. SFAS 141(R) establishes principles and requirements for how an acquirer in a business combination: (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The adoption of this pronouncement may have a material impact on the accounting for any acquisition the Company may make after January 1, 2009.

In December 2007, the FASB issued SFAS No. 160, *"Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51"* ("SFAS 160"). This statement amends ARB No. 51 to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. This statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The Company does not expect the adoption of this pronouncement to have a material impact on the Company's financial position or results of operations.

(2) ACQUISITIONS AND DIVESTITURES:

Acquisitions

Acquisition of Houston Exploration

On June 6, 2007, Forest completed the acquisition of The Houston Exploration Company ("Houston Exploration") in a cash and stock transaction totaling approximately $1.5 billion and the assumption of Houston Exploration's debt. Houston Exploration was an independent natural gas and oil producer engaged in the exploration, development, exploitation, and acquisition of natural gas and oil reserves in North America. Houston Exploration had operations in four producing regions within the United States: South Texas, East Texas, the Arkoma Basin of Arkansas, and the Uinta and DJ Basins in the Rocky Mountains. The principal factors considered by management in making the acquisition included the mix of complementary high-quality assets in certain of the Company's 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. Pursuant to the terms and conditions of the agreement and plan of merger ("Merger Agreement"), Forest paid total merger consideration of $750 million in cash and issued approximately 24 million common shares, valued at $30.28 per share. The per share value of the Forest common shares issued was calculated as the average of Forest's closing share price for a five day period surrounding the announcement date of the acquisition on January 7, 2007. The cash component of the merger consideration was financed from a private placement of $750 million of 7¼% senior notes due 2019 and borrowings under the Company's $1.0 billion second amended and restated credit facilities that were executed on June 6, 2007. Immediately following the completion of the merger, Forest repaid all of Houston Exploration's outstanding bank debt totaling $177 million.

The acquisition, which was accounted for using the purchase method of accounting, has been included in Forest's Consolidated Financial Statements since June 6, 2007, the date the acquisition closed. The following table represents the preliminary allocation of the total purchase price of Houston Exploration to the acquired assets and liabilities of Houston Exploration as of December 31, 2007. The allocation represents the estimated fair values assigned to each of the assets acquired and liabilities assumed. The purchase price allocation is preliminary, subject to the completion of evaluations of proved and unproved oil and gas properties, deferred income taxes, contractual arrangements, and legal and environmental matters. These and other estimates are subject to change as additional information becomes available and is assessed by Forest.

	(In Thousands)
Fair value of Houston Exploration's net assets:	
Net working capital, including cash of $3.5 million	$ (33,551)
Proved oil and gas properties	1,741,823
Unproved oil and gas properties	448,100
Goodwill	176,761
Other assets	14,537
Derivative instruments	(45,170)
Long-term debt	(182,532)
Asset retirement obligations	(36,424)
Deferred income taxes	(559,136)
Other liabilities	(19,099)
Total fair value of net assets	$1,505,309
Consideration paid for Houston Exploration's net assets:	
Forest common stock issued	$ 726,412
Cash consideration paid	749,694
Aggregate purchase consideration paid to Houston Exploration stockholders	1,476,106
Plus:	
Cash settlement for Houston Exploration stock options	20,075
Direct merger costs incurred	9,128
Total consideration paid	$1,505,309

Goodwill of $176.8 million has been recognized to the extent that the consideration paid exceeded the fair value of the net assets acquired and has been assigned to the U.S. geographical business segment. Goodwill is not expected to be deductible for tax purposes. The principal factors that contributed to the recognition of goodwill include the mix of complementary high-quality assets in certain 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.

Included in the working capital assumed at the acquisition date was a severance accrual of $28.9 million for costs to involuntarily terminate employees of Houston Exploration. Management determined it would be necessary to eliminate certain overlapping positions to achieve cost savings through administrative and operational synergies. Management is still finalizing its business integration plans as a result of the acquisition and, accordingly, the severance accrual will be finalized once these

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

plans are complete. The following table summarizes the activity in the severance accrual through December 31, 2007 since the acquisition date:

	(In Thousands)
Severance accrual at June 6, 2007	$ 28,850
Cash payments[1]	(11,519)
Net adjustment[2]	(1,694)
Severance accrual at December 31, 2007	$ 15,637

[1] Represents cash severance and excise tax payments to involuntarily terminated employees of Houston Exploration as well as the related employer tax payments paid by the Company.

[2] Represents the net adjustment made to the accrual as the Company continues to finalize the termination plan. This net adjustment was made to the cost of the acquired company.

The remaining severance payments are expected to be made during 2008.

The following summary pro forma combined statement of operations data of Forest for the years ended December 31, 2007 and 2006 has been prepared to give effect to the merger as if the merger had occurred on January 1, 2007 and 2006, respectively. The pro forma financial information is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2007 and 2006, and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following pro forma financial information because of normal production declines, changes in commodity prices, future acquisitions and divestitures, future development and exploration activities, and other factors. The pro forma financial information also gives pro forma effect to Forest's spin-off of its offshore Gulf of Mexico operations completed in March 2006 and Houston Exploration's sale of substantially all of its offshore Gulf of Mexico operations completed in June 2006, as though each disposition occurred on January 1, 2006.

	Year Ended December 31,	
	2007	2006
	(In Thousands, Except Per Share Amounts)	
Revenues	$1,304,849	1,220,447
Earnings from continuing operations	181,591	172,101
Net earnings	181,591	174,523
Basic earnings per common share:		
From continuing operations	$ 2.09	2.00
Basic earnings per common share	2.09	2.02
Diluted earnings per common share:		
From continuing operations	$ 2.06	1.98
Diluted earnings per common share	2.06	2.00

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. Forest funded this acquisition utilizing its bank credit facilities.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

Buffalo Wallow Acquisition

On April 1, 2005, Forest purchased a private company whose primary assets were located in the Buffalo Wallow field, primarily in Hemphill and Wheeler Counties, Texas ("the Buffalo Wallow Acquisition"). The purchase price was allocated to assets and liabilities, adjusted for tax effects, based on their estimated fair values at the date of acquisition. The acquisition was accounted for using the purchase method of accounting and has been included in the consolidated financial statements of Forest since the date of acquisition.

The 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.

Divestitures

Sale of Alaska Assets

On August 27, 2007, Forest sold all of its assets located in Alaska (the "Alaska Assets") to Pacific Energy Resources Ltd. ("PERL"). The total consideration received for the Alaska Assets included $400 million in cash, 10 million shares of PERL common stock (subject to certain restrictions), and a zero coupon senior subordinated note from PERL due 2014 in the principal amount at stated maturity of $60.8 million. A portion of the cash consideration, $269 million, was applied to prepay all amounts due under the term loan agreements, including accrued interest and prepayment premiums. Consideration received by Forest in the form of the PERL common stock and the zero coupon senior subordinated note are being held in other investments within the Consolidated Balance Sheet. Forest accounts for these investments as trading securities in accordance with SFAS No. 115, "*Accounting for Certain Investments in Debt and Equity Securities*." Investments in debt and equity securities classified as trading securities are recorded at fair value with unrealized gains and losses recognized in "Other income and expense" in the Consolidated Statements of Operations.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

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 approximately 50.6 million 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 $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. In accordance with the transaction agreements, Forest and MERI had submitted post-closing adjustments from which Forest paid MERI a total of $5.8 million during 2007. Additional adjustments to the cash amount may occur pending the resolution of certain accounting matters that are the subject of ongoing arbitration between Forest and MERI. The arbitration is currently expected to be concluded in the second half of 2008.

The table below sets forth the assets and liabilities included in the Spin-off (in thousands):

Working capital	$ (12,383)
Proved oil and gas properties, net of accumulated depletion	1,033,289
Unproved oil and gas properties	38,523
Other assets	7,919
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

The following table presents the revenues and direct operating expenses of the offshore Gulf of Mexico operations reported in the Consolidated Statements of Operations for all periods presented. As

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

the spin-off of the offshore Gulf of Mexico operations were concluded in 2006, the Company did not have operating activity from offshore Gulf of Mexico operations during 2007.

	Year Ended December 31,	
	2006	2005
	(In Thousands)	
Revenues	$46,289	392,272
Oil and gas production expense:		
Lease operating expenses	18,296	78,524
Transportation and processing costs	344	3,383
Production and property taxes	151	2,215
Revenues in excess of direct operating expenses	$27,498	308,150

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 years ended December 31, 2007 and 2005, Forest did not receive any additional contingent payments. During the year ended December 31, 2006, Forest received an additional $3.6 million contingent payment ($2.4 million net of tax) under the agreement, which has been reflected as income from discontinued operations in the Consolidated Statements of Operations.

Other Divestitures

During the year ended December 31, 2007, Forest sold properties in addition to the Alaska Assets for total proceeds of $39.4 million, including an overriding royalty interest in Australia for net proceeds of $7.2 million that resulted in a gain on the sale of $7.2 million. In addition, in August 2007, the Company entered into a sale-leaseback transaction whereby the Company sold its drilling rigs for cash proceeds of $62.6 million and simultaneously entered into an operating lease with the buyer which provides for monthly rental payments of $.9 million for a term of seven years. A deferred gain of $33.3 million resulted from the sale of the drilling rigs and will be amortized over the term of the lease.

(3) PROPERTY AND EQUIPMENT:

Net property and equipment at December 31, 2007 and 2006 consists of the following:

	2007	2006
	(In Thousands)	
Oil and gas properties:		
Proved	$ 7,157,249	4,751,171
Unproved	568,510	261,259
Accumulated depletion	(2,742,539)	(2,265,018)
Net oil and gas properties	4,983,220	2,747,412
Other property and equipment:		
Furniture and fixtures, computer hardware and software, and other equipment	72,606	75,018
Accumulated depreciation and amortization	(30,011)	(32,504)
Net other property and equipment	42,595	42,514
Total net property and equipment	$ 5,025,815	2,789,926

The following table sets forth a summary of oil and gas property costs not being depleted at December 31, 2007, by the year in which such costs were incurred:

	Total	2007	2006	2005	2004 and Prior
			(In Thousands)		
United States:					
Acquisition costs	$382,531	357,849	18,836	985	4,861
Exploration costs	63,418	27,061	26,907	8,117	1,333
Total United States	445,949	384,910	45,743	9,102	6,194
Canada:					
Acquisition costs	25,512	—	—	4,142	21,370
Exploration costs	38,439	20,495	13,568	65	4,311
Total Canada	63,951	20,495	13,568	4,207	25,681
International:					
Acquisition costs	740	—	—	—	740
Exploration costs	57,870	1,911	5,151	1,360	49,448
Total International	58,610	1,911	5,151	1,360	50,188
Total	$568,510	407,316	64,462	14,669	82,063

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, 2007 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 $58.6 million are not being depleted pending determination of the existence of estimated proved reserves. Forest's exploration project in South Africa accounts for the majority of the international costs not being amortized. In 2007, 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, 2007				December 31, 2006			
	Principal	Unamortized Premium (Discount)	Other[3]	Total	Principal	Unamortized Premium (Discount)	Other[3]	Total
				(In Thousands)				
U.S. Credit Facility	$ 165,000	—	—	165,000	23,000	—	—	23,000
Canadian Credit Facility	129,126	—	—	129,126	84,094	—	—	84,094
Alaska Credit Agreements[1]	—	—	—	—	375,000	—	—	375,000
8% Senior Notes due 2008	265,000	(48)	1,050	266,002	265,000	(146)	3,346	268,200
8% Senior Notes due 2011	285,000	5,167	3,315	293,482	285,000	6,458	4,152	295,610
7% Senior Subordinated Notes due 2013[2]	5,822	(158)	—	5,664	—	—	—	—
7¾% Senior Notes due 2014	150,000	(1,512)	11,275	159,763	150,000	(1,751)	13,056	161,305
7¼% Senior Notes due 2019[2]	750,000	—	—	750,000	—	—	—	—
Total debt	1,749,948	3,449	15,640	1,769,037	1,182,094	4,561	20,554	1,207,209
Less: current portion of long-term debt	(265,000)	48	(1,050)	(266,002)	(2,500)	—	—	(2,500)
Long-term debt	$1,484,948	3,497	14,590	1,503,035	1,179,594	4,561	20,554	1,204,709

(1) On August 27, 2007, in connection with the sale of the Alaska Assets, Forest paid all outstanding amounts owed under its Alaska Credit Agreements.

(2) In connection with the acquisition of Houston Exploration, Forest assumed approximately $5.8 million of 7% senior subordinated notes due 2013 and issued $750 million of 7¼% senior notes due 2019 for net proceeds of approximately $739.2 million after deducting initial purchasers' discounts.

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

Bank Credit Facilities

The Company currently has credit facilities totaling $1.0 billion, consisting of an $850 million U.S. credit facility through a syndicate of banks led by JPMorgan Chase Bank, N.A. and a $150 million Canadian credit facility through a syndicate of banks led by JPMorgan Chase Bank, N.A., Toronto Branch. The credit facilities mature in June 2012. Subject to the agreement of Forest and the applicable lenders, the size of the credit facilities may be increased by $800 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 June 6, 2007, the syndicate of banks approved a Global Borrowing Base of $1.4 billion, with the U.S. allocated borrowing base at $1.25 billion and the Canadian allocated borrowing base at $150 million.

At December 31, 2007, there were outstanding borrowings of $165.0 million under the U.S. credit facility at a weighted average interest rate of 6.2%, and there were outstanding borrowings of $129.1 million under the Canadian credit facility at a weighted average interest rate of 5.9%. Forest also had used the credit facilities for approximately $2.6 million in letters of credit, leaving an unused borrowing amount under the credit facilities of approximately $703.3 million at December 31, 2007.

(4) DEBT: (Continued)

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 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.

Alaska Credit Agreements

On December 8, 2006, Forest, through its wholly-owned subsidiaries, Forest Alaska Operating LLC and Forest Alaska Holding LLC (together "Forest Alaska"), 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 "Alaska 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.

During the year ended December 31, 2007, Forest Alaska made scheduled repayments of $1.3 million and a voluntary prepayment of $110.0 million on the first lien credit agreement. In conjunction with the sale of the Alaska Assets on August 27, 2007, Forest used a portion of the $400 million cash consideration to repay the remaining $263.7 million principal balance outstanding

(4) DEBT: (Continued)

under the Alaska Credit Agreements. During the year ended December 31, 2007, Forest recognized debt extinguishment costs of $12.2 million associated with payments on the Alaska Credit Agreements. The debt extinguishment costs included $5.0 million in prepayment premiums on the Alaska Credit Agreements and $7.2 million of unamortized debt issuance costs.

8% Senior Notes Due 2008

In June 2001, Forest issued $200 million in principal amount of 8% senior notes due 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). The 8% Notes due 2008 are redeemable, at the Company's option, in whole or in part, at any time at the principal amount, plus accrued interest, and a make-whole premium. The 8% Notes Due 2008 will mature on June 15, 2008. Upon maturity, the Company expects to repay all outstanding principal and interest through cash flow from operations and its existing bank credit facilities.

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% Notes Due 2011 at 107.75% of par for proceeds of $133.3 million (net of related offering costs). The 8% Notes due 2011 are redeemable, at the Company's option, in whole or in part, at any time at the principal amount, plus accrued interest, and a make-whole premium. Interest is payable on June 15 and December 15 of each year.

7% Senior Subordinated Notes Due 2013

In connection with the acquisition of Houston Exploration, Forest assumed $5.8 million of 7% senior subordinated notes due 2013 (the "7% Notes") originally issued by Houston Exploration in June 2003. The 7% Notes may be redeemed at the option of the Company, in whole or in part, at any time on or after June 15, 2008 at a price equal to 100% of the principal amount plus accrued but unpaid interest, if any, plus a specified premium that decreases yearly from 3.5% in 2008 to 0% in 2011 and thereafter. Interest is payable on June 15 and December 15 of each year.

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 Company's option, at any time on or after May 1, 2007, at the approximate redemption rates set forth below, plus accrued and unpaid interest. Interest is payable on May 1 and November 1 of each year.

	Redemption Rate
2008	102.6%
2009	101.3%
2010 and thereafter	100.0%

(4) DEBT: (Continued)

7¼% Senior Notes Due 2019

On June 6, 2007, Forest issued $750 million of 7¼% senior notes due 2019 (the "7¼% Notes") at par for net proceeds of approximately $739.2 million, after deducting initial purchaser discounts. Interest is payable on June 15 and December 15 of each year. The Company may redeem up to 35% of the 7¼% Notes at any time prior to June 15, 2010, on one or more occasions, with the proceeds from certain equity offerings at a redemption price equal to 107.25% of the principal amount, plus accrued but unpaid interest. The Company may redeem the 7¼% Notes at any time beginning on or after June 15, 2012 at the prices set forth below, expressed as percentages of the principal amount redeemed, plus accrued but unpaid interest:

	Redemption Rate
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

Principal Maturities

Principal maturities of the Company's debt at December 31, 2007 are as follows (in thousands):

	Principal Maturities
2008	$265,000
2011	285,000
2012	294,126
Thereafter	905,822

(5) INCOME TAXES:

The Company accounts for income taxes in accordance with the provisions of SFAS 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,		
	2007	2006	2005
	(In Thousands)		
Current:			
Federal	$ 3,503	1,341	3,738
Foreign	(1,798)	140	238
State	4,294	645	(478)
	5,999	2,126	3,498
Deferred:			
Federal	58,536	77,445	55,608
Foreign	(2,098)	3,643	24,310
State, net	(42)	7,689	9,942
	56,396	88,777	89,860
	$62,395	90,903	93,358

(5) INCOME TAXES: (Continued)

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.

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

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands)		
United States federal	$177,999	211,785	168,024
Foreign	53,702	45,198	76,902
	$231,701	256,983	244,926

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

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands)		
Federal income tax at 35% of income before income taxes and discontinued operations	$ 81,095	89,944	85,724
State income taxes, net of federal income tax benefits	2,960	7,616	5,759
Change in the valuation allowance for deferred tax assets	(1,831)	(1,464)	(5,460)
Effect of differing tax rates in Canada	(1,517)	(160)	1,537
Effect of taxable dividends repatriated under Section 965 of the I.R.C.	—	—	4,275
Effect of Canadian statutory rate reductions	(16,815)	(12,292)	(3,129)
Effect of state statutory rate reductions	(2,397)	(5,706)	—
Effects related to the Spin-off	—	7,209	—
Other	900	5,756	4,652
Total income tax expense	$ 62,395	90,903	93,358

(5) INCOME TAXES: (Continued)

The components of the net deferred tax liability by geographical segment at December 31, 2007 and 2006 are as follows:

	December 31, 2007		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Allowance for doubtful accounts	$ 443	—	443
Investment in PERL common stock	1,776	—	1,776
Accrual for post retirement benefits	4,703	—	4,703
Stock-based compensation accruals under SFAS 123(R)	7,755	—	7,755
Net operating loss carryforwards	142,436	238	142,674
Capital loss carryforward	—	3,004	3,004
Depletion carryforward	7,137	—	7,137
Alternative minimum tax credit carryforward	10,352	—	10,352
Unrealized losses on derivative contracts, net	29,394	—	29,394
Other	15,537	1,817	17,354
Total gross deferred tax assets	219,533	5,059	224,592
Less valuation allowance	(27,036)	(811)	(27,847)
Net deferred tax assets	192,497	4,248	196,745
Deferred tax liabilities:			
Property and equipment	(932,508)	(92,401)	(1,024,909)
Other	—	(1,409)	(1,409)
Total gross deferred tax liabilities	(932,508)	(93,810)	(1,026,318)
Net deferred tax liabilities	$(740,011)	(89,562)	(829,573)

	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 gains 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)

(5) INCOME TAXES: (Continued)

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

	December 31, 2007		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax assets	$ 23,854	—	23,854
Non-current deferred tax liabilities	(763,865)	(89,562)	(853,427)
Net deferred tax liabilities	$(740,011)	(89,562)	(829,573)

	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)

U.S. federal net operating loss carryforwards at December 31, 2007 were approximately $427.1 million. Of this amount, approximately $141.4 million was acquired by the Company in a merger that occurred in 2000, approximately $38.9 million was acquired by the Company in its acquisitions of other corporate entities in 2004 and 2005, and $61.8 million was acquired by the Company in the Houston Exploration acquisition in June 2007. The Company's federal net operating losses are scheduled to expire in years 2009 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 $27.0 million, recognizing the effects of Section 382 on its ability to ever realize these carryforwards.

In accordance with SFAS 123(R), windfall deductions from the exercise of stock-based compensation awards that do not result in a reduction in income taxes payable, should not be recorded. The Company uses the "with and without method" for realization of the tax benefits of the windfall deductions. As a result, NOLs related to the windfall deductions of $21.0 million will be recorded in capital surplus when realized as a reduction of income taxes payable.

The net changes in the total valuation allowance for the years ended December 31, 2007, 2006, and 2005 were as follows:

	2007	2006	2005
	(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)
Decrease in the valuation allowance for net expiring operating loss carryforwards	—	(9,967)	(3,483)
Other decreases in the valuation allowance for deferred tax assets	(1,831)	(1,465)	(2,443)
Net decrease in the valuation allowance	$(1,831)	(19,769)	(42,534)

(5) INCOME TAXES: (Continued)

The decrease in the valuation allowance for 2007 of $1.8 million relates to adjustments to Canadian tax loss carryforwards.

$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 2006. 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.

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 $10.4 million at December 31, 2007. 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 $309.9 million ($304 million CDN) at December 31, 2007. The Canadian tax pools include approximately $45.4 million ($44.5 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:

	2007	2006
	(In Thousands of Canadian Dollars)	
Canadian capital cost allowance (deductible at 4% - 45% annually)	$100,652	76,051
Canadian development expense (deductible at 30% annually)	146,927	130,792
Canadian exploration expense (deductible at 100% annually)	8,481	1,704
Canadian oil and gas property expense (deductible at 10% annually)	47,941	46,387
	$304,001	254,934

Other Canadian tax pools and loss carryforwards available to reduce future Canadian federal income taxes were approximately $18.0 million ($17.7 million CDN) at December 31, 2007, of which $17.1 million may be carried forward indefinitely.

The Company's Canadian operations generated book income (after tax) of approximately $57.6 million during 2007. As of December 31, 2007, the Company's Canadian operations had reported accumulated undistributed book earnings of approximately $140 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 2007, 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

(5) INCOME TAXES: (Continued)

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.

The Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes", an interpretation of SFAS 109, *"Accounting for Income Taxes"* ("FIN 48"), on January 1, 2007. As a result of the implementation of FIN 48 the Company recognized a liability for uncertain tax benefits of approximately $1.0 million, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings. The adoption of FIN 48 increased the Company's previously recognized liability for uncertain tax benefits of $.5 million to $1.5 million. The $1.5 million liability does not relate to uncertainties about the timing of items of income or deduction and would affect the Company's effective tax rate if recognized in the Company's income tax provision. The Company records interest accrued related to unrecognized tax benefits in interest expense and penalties in other expense, to the extent they apply. The Company recognized no significant interest or penalties at the date of its adoption of FIN 48.

There was no change in the amount of unrecognized tax benefits during the year ended December 31, 2007. In conjunction with the Houston Exploration acquisition, Forest assumed an additional liability for uncertain tax benefits of $1.6 million. The Company does not expect any significant change in the total amounts of unrecognized tax benefits within the twelve months ending December 31, 2008.

A reconciliation of the beginning and ending balances of the total amounts of gross unrecognized tax benefits is as follows (in thousands):

Gross unrecognized tax benefits at January 1, 2007	$ 487
Increases in tax positions for prior years at January 1, 2007	1,040
Increases in tax positions for acquired entities	1,640
Gross unrecognized tax benefits at December 31, 2007	$3,167

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $1.5 million, net of estimated accrued interest and penalties.

The statute of limitations is closed for the Company's U.S. federal income tax returns for years ending before and including December 31, 2003. Pre-acquisition returns of acquired businesses are also closed for tax years ending before and including December 31, 2003. However, the Company has utilized, and will continue to utilize, net operating losses ("NOLs") (including NOLs of acquired businesses) in its open tax years. The earliest available NOLs were generated in the tax year beginning January 1, 1989, but are potentially subject to adjustment by the federal tax authorities in the tax year in which they are utilized. Thus, the Company's earliest U.S. federal income tax return that is closed to potential audit adjustments is the tax year ending December 31, 1988. The Company's most recent Canadian income tax return that is closed to potential audit adjustments is the tax year ended December 31, 2002.

(6) SHAREHOLDERS' EQUITY:

Common Stock

At December 31, 2007, the Company had 200 million shares of common stock ("Common Stock"), par value $.10 per share, authorized.

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 and issued rights that will expire on October 29, 2013, unless earlier exchanged or redeemed, that entitle the holder thereof to purchase 1/100th of a preferred share at an initial purchase price of $120.

(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 2007 and 2006 under the provisions of SFAS 123(R), the remaining unamortized amounts and the weighted average amortization period remaining as of December 31, 2007. Approximately $9.7 million of the

(7) STOCK-BASED COMPENSATION: (Continued)

$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.

	Stock Options	Restricted Stock	Phantom Stock Units	Total[1]
		(In Thousands)		
Year ended December 31, 2007:				
Total stock-based compensation costs	$ 5,006	10,142	2,177	17,325
Less: stock-based compensation costs capitalized	(1,485)	(3,920)	(1,381)	(6,786)
Stock-based compensation costs expensed	$ 3,521	6,222	796	10,539
Unamortized stock-based compensation costs as of December 31, 2007	$ 5,566	29,431	5,362[2]	40,359
Weighted average amortization period remaining	1.8 years	1.9 years	1.8 years	1.9 years
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

(1) The Company also maintains an employee stock purchase plan (which is not included in the table above) under which $.4 million and $.3 million of compensation cost was recognized for the years ended December 31, 2007 and December 31, 2006, respectively, under the provisions of SFAS 123(R).

(2) Based on the closing price of the Company's Common Stock on December 31, 2007.

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 2007, the Company adopted the Forest Oil Corporation 2007 Stock Incentive Plan (the "2007 Plan") under which qualified and non-qualified stock options, restricted stock, phantom stock units, and other awards may be granted to employees, consultants, and non-employee directors. The aggregate number of shares of Common Stock that the Company may issue under the 2007 Plan may not exceed 2.7 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 granted under the 2007 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. Restricted stock awards generally vest three years from the date of the grant. As of December 31, 2007, the Company had 2,166,985 shares available to be issued under the 2007 Plan.

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

(7) STOCK-BASED COMPENSATION: (Continued)

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. Restricted stock awards generally vest three years from the date of the grant. As of December 31, 2007, the Company had 112,975 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.

Stock Options

The following table summarizes stock option activity in the Company's stock-based compensation plans for the years ended December 31, 2007, 2006, and 2005. 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.

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)[1]	Number of Shares Exercisable
Outstanding at January 1, 2005	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
Granted	666,655	42.16		
Exercised	(652,220)	18.07	15,610	
Cancelled	(401,208)	40.07		
Outstanding at December 31, 2007	2,941,506	21.35	87,816	2,275,314

(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.

(7) STOCK-BASED COMPENSATION: (Continued)

The fair value of each option granted in 2007, 2006, and 2005 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:

	2007	2006	2005
Expected life of options	5.4 years	10 years	5 years
Risk free interest rates	4.65% - 5.13%	4.64% - 5.13%	3.64% - 4.45%
Estimated volatility	32%	45%	28%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of options granted during the year	$16.14	$23.35	$12.77

The following table summarizes information about options outstanding at December 31, 2007:

	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 – 16.82	716,748	4.82	$15.63	$25,496	716,748	$15.63	$25,496
16.83 – 18.19	747,590	5.31	17.33	25,324	603,839	17.44	20,389
18.26 – 20.47	230,800	3.56	19.82	7,244	215,758	19.83	6,769
20.60 – 20.60	612,760	6.89	20.60	18,754	432,492	20.60	13,236
20.62 – 44.57	633,608	7.62	33.85	10,998	306,477	28.28	7,025
$8.41 – 44.57	2,941,506	5.88	21.35	$87,816	2,275,314	19.16	$72,915

Restricted Stock and Phantom Stock Units

The following table summarizes the restricted stock and phantom stock unit activity for the years ended December 31, 2007, 2006, and 2005. 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, 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, 2005	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
Awarded	784,700	42.17	90,700	41.01
Vested	(82,450)	30.26	—	—
Forfeited	(48,700)	42.20	(4,150)	44.17
Unvested at December 31, 2007	1,281,000	43.41	164,500	42.50

(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 who held phantom stock units on that date representing the per-share value of the MERI shares received by each holder of restricted stock.

(7) STOCK-BASED COMPENSATION: (Continued)

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 during the year ended December 31, 2005 related to these equity awards.

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. Currently, under the terms of the ESPP, employees may elect each calendar 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 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, 2007, the Company had 128,876 shares available for issuance under the ESPP.

The fair value of each stock purchase right granted under the ESPP during 2007, 2006, and 2005 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:

	2007	2006	2005
Expected option life	3 months	3 months	3 months
Risk free interest rates	3.92% - 5.07%	4.16% - 5.08%	2.32% - 3.61%
Estimated volatility	26%	21%	26%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of purchase rights granted	$10.88	$9.38	$12.11

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 SFAS No. 123, "*Accounting for Stock-*

(7) STOCK-BASED COMPENSATION: (Continued)

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

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

(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 Oil Company 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. In conjunction with the Houston Exploration acquisition in June 2007, Forest assumed a non-qualified unfunded supplementary retirement plan (the "Houston Exploration SERP"). The Houston Exploration SERP was curtailed and all benefit accruals were suspended effective January 1, 2008. The Forest Pension Plan, the Wiser Pension Plan, the SERP, and the Houston Exploration 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 Canada are closed to new participants.

(8) EMPLOYEE BENEFITS: (Continued)

Investments of the Plans

The weighted average asset allocations of the Forest Pension Plan and Wiser Pension Plan at December 31, 2007 and 2006 are set forth in the following table:

	Forest Pension Plan		Wiser Pension Plan	
	2007	2006	2007	2006
Fixed income securities	33%	33%	29%	28%
Equity securities	66%	64%	70%	67%
Other	1%	3%	1%	5%
	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 current targeted goal for equity securities exposure is 65% of plan assets at market value. There is no specified minimum equity exposure for any point in time. The current targeted goal for fixed income exposure is 35% of the plan assets at market value. 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 trust and the Wiser Pension Plan trust and fund benefit payments directly for the SERP and the Houston Exploration SERP and the other postretirement benefits plans in 2008 through 2012 and in the aggregate for the years 2013 through 2017 in the following amounts:

	2008	2009	2010	2011	2012	2013-2017
			(In Thousands)			
Forest Pension Plan(1)	$2,407	2,397	2,378	2,344	2,293	10,837
SERP	61	59	56	54	51	206
Wiser Pension Plan(1)	825	822	821	814	803	4,033
Houston Exploration SERP	100	98	96	94	91	408
Postretirement benefits (U.S.)	574	566	569	575	554	2,723
Postretirement benefits (Canada)	51	54	59	62	66	387

(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 2008 totaling $.2 million to the Plans and $.5 million for the Postretirement Benefit plans, net of retiree contributions and expected medicare reimbursements, 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, 2007 and 2006.

(8) EMPLOYEE BENEFITS: (Continued)

Amounts for the Forest Pension Plan, the SERP, the Houston Exploration SERP, and the Wiser Pension Plan are combined in the "Pension Benefits" columns.

Benefit Obligations

	Pension Benefits		Postretirement Benefits	
	2007	2006	2007	2006
	(In Thousands)			
Benefit obligation at the beginning of the year	$40,556	42,804	8,457	10,297
Acquisition	1,064	—	585	—
Service cost	—	—	467	580
Interest cost	2,247	2,192	453	453
Actuarial gain	(164)	(1,257)	(1,210)	(271)
Effect of curtailment	—	—	—	(2,092)
Benefits paid	(3,282)	(3,183)	(520)	(584)
Medicare reimbursements	—	—	57	7
Retiree contributions	—	—	67	68
Impact of foreign currency exchange rate	—	—	220	(1)
Benefit obligation at the end of the year	$40,421	40,556	8,576	8,457

Fair Value of Plan Assets

	Pension Benefits		Postretirement Benefits	
	2007	2006	2007	2006
	(In Thousands)			
Fair value of plan assets at beginning of the year	$37,615	34,472	—	—
Actual return on plan assets	2,875	3,761	—	—
Retiree contributions	—	—	67	68
Medicare reimbursements	—	—	57	7
Employer contribution	623	2,565	396	509
Benefits paid	(3,282)	(3,183)	(520)	(584)
Fair value of plan assets at the end of the year	$37,831	37,615	—	—

(8) EMPLOYEE BENEFITS: (Continued)

Funded Status

	Pension Benefits		Postretirement Benefits	
	2007	2006	2007	2006
	(In Thousands)			
Excess of benefit obligation over plan assets	$(2,590)	(2,941)	(8,576)	(8,457)
Unrecognized actuarial loss (gain)	9,169	10,422	(1,326)	(271)
Net amount recognized	$ 6,579	7,481	(9,902)	(8,728)
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability	$(2,590)	(2,941)	(8,576)	(8,457)
Accumulated other comprehensive income—net actuarial loss (gain)	9,169	10,422	(1,326)	(271)
Net amount recognized	$ 6,579	7,481	(9,902)	(8,728)

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.

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,	
	2007	2006
	(In Thousands)	
Projected benefit obligation	$40,421	40,556
Accumulated benefit obligation	40,421	40,556
Fair value of plan assets	37,831	37,615

(8) EMPLOYEE BENEFITS: (Continued)

Annual Periodic Expense and Actuarial Assumptions

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, 2007, 2006, and 2005:

	Pension Benefits			Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
	(In Thousands)					
Service cost	$ —	—	—	467	580	671
Interest cost	2,247	2,192	2,325	453	453	493
Curtailment gain[1]	—	—	—	—	(1,851)	—
Expected return on plan assets	(2,562)	(2,430)	(2,346)	—	—	—
Recognized actuarial loss (gain)	778	899	753	(35)	—	—
Amortization of prior service cost	—	10	—	—	—	—
Total net periodic expense (benefit)	$ 463	671	732	885	(818)	1,164
Assumptions used to determine net periodic expense:						
Discount rate	5.64% & 5.90%	5.32%	5.75%	3.98% & 5.75%	4.72% & 5.46%	5.75% & 6.00%
Expected return on plan assets	7%	7% & 8%	7% & 8%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:						
Discount rate	5.77%	5.64%	5.32%	5.39% & 6.02%	3.98% & 5.75%	4.72% & 5.46%

(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, 2008, will include expense of $.5 million resulting from the amortization of its related accumulated actuarial loss included in accumulated other comprehensive income at December 31, 2007.

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 2007 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 9% in 2008, 8% in 2009, 7% in 2010, and 6% thereafter for the medical plan.

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 2007:

	Postretirement Benefits	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	$ 186	(143)
Effect on postretirement benefit obligation	$1,223	(988)

(8) EMPLOYEE BENEFITS: (Continued)

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. From January 1, 2004 through December 31, 2007, the Company matching percentage was 7% of eligible employee compensation. Effective January 1, 2008, the Company matching percentage increased to 8%. Expenses associated with the Company's contributions to the Retirement Savings Plan totaled $2.2 million in 2007, $1.9 million in 2006, and $2.2 million in 2005. 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 9% of their compensation, subject to certain limitations, with Canadian Forest matching 4% of the eligible employee compensation. The expense associated with Canadian Forest's contributions to the plan was approximately $.3 million in 2007 and $.2 million in each of 2006 and 2005. 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 $.3 million in 2007, $.2 million in 2006, and $.3 million in 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 $.2 million in 2007, $.3 million in 2006, and $.4 million in 2005. 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 $3.1 million and $2.4 million at December 31, 2007 and 2006, respectively.

In conjunction with the Houston Exploration acquisition, Forest assumed Houston Exploration's deferred compensation plan (the "Houston Exploration Plan"). The Houston Exploration Plan was frozen to new employees, and all deferrals into the plan (including matching contributions) were suspended on January 1, 2008. The assets of the Houston Exploration Plan are held by a grantor trust and are invested, at the direction of the employee, in various investment funds. At December 31, 2007, the fair value of the assets held in the trust (the main component of which is trust owned life insurance policies) was $10.5 million. The expense associated with the Company's matching contributions to the Houston Exploration Plan was $.1 million in 2007. The fair value of the amounts deferred under the Houston Exploration Plan was $7.4 million at December 31, 2007.

Split Dollar Life Insurance

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

(9) DERIVATIVE INSTRUMENTS AND FIXED-PRICE CONTRACTS:

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. 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 hedge accounting 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 cash flow hedge accounting are recorded as additions to or reductions of 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 for all of its 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 table below summarizes the realized and unrealized gains and losses Forest incurred related to its oil and gas derivative instruments for the periods indicated:

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands)		
Realized losses on derivatives designated as cash flow hedges[1]	$ —	43,813	186,442
Realized (gains) losses on derivatives not designated as cash flow hedges[2][3]	(75,491)	23,864	35,390
Ineffectiveness recognized on derivatives designated as cash flow hedges[2]	—	(5,573)	5,747
Unrealized losses (gains) on derivatives not designated as cash flow hedges[2]	112,778	(78,056)	15,626
Total realized and unrealized losses (gains) recorded	$ 37,287	(15,952)	243,205

(1) Included in "Revenues" in the Consolidated Statements of Operations. Realized gains or losses on derivatives that had previously been designated as cash flow hedges at the time the Company elected to discontinue hedge accounting were required to be included as part of "Revenues".

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

(3) Includes total proceeds of $6.9 million for two oil swap agreements that the Company unwound in 2007, which covered 1,000 Bbl per day in 2009 and 500 Bbl per day in 2010.

(9) DERIVATIVE INSTRUMENTS AND FIXED-PRICE CONTRACTS: (Continued)

The tables below set forth Forest's outstanding commodity swaps and collars as of December 31, 2007:

	Swaps			
	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	Bbtu Per Day[(1)]	Weighted Average Hedged Price per MMBtu	Barrels Per Day	Weighted Average Hedged Price per Bbl
Calendar 2008	50	$8.38	6,500	$69.72
Calendar 2009	—	—	4,500	69.01
Calendar 2010	—	—	1,500	72.95

(1) 10 Bbtu per day is subject to a $6.00 written put.

	Costless Collars	
	Natural Gas (NYMEX HH)	
	Bbtu per Day	Weighted Average Hedged Floor and Ceiling Price per MMBtu
January – February 2008	130	$7.39/8.89
March – December 2008	80	7.33/8.87

	Three-Way Costless Collars	
	Natural Gas (NYMEX HH)	
	Bbtu per Day	Weighted Average Hedged Lower Floor, Upper Floor, and Ceiling Price per MMBtu
January – February 2008	20	$6.00/8.00/10.00
March – December 2008	30	6.00/8.00/10.00

Forest also uses basis swaps in connection with natural gas swaps in order to fix the price differential between the NYMEX price and the index price at which the natural gas production is sold. As of December 31, 2007, the Company had basis swaps outstanding covering 80 Bbtu per day for 2008.

At December 31, 2007, the fair values of Forest's commodity derivative instruments are presented within the Consolidated Balance Sheet as liabilities of $106.1 million, of which $70.6 million is classified as current, and assets of $30.0 million, all of which is 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.

In January and February 2008, the Company entered into six additional gas swap agreements for 60 Bbtu per day at a weighted average hedged price per MMBtu of $8.99 for calendar 2009. In February 2008, the Company entered into an additional gas costless collar agreement for 20 Bbtu per day with a hedged floor and ceiling price per MMBtu of $8.00 and $10.56, respectively, for calendar 2009.

The Company may enter into interest rate swap agreements in an attempt to normalize the mix of fixed and floating interest rates within its debt portfolio. Unrealized gains, losses, or any settlements are recorded in other income and expense in the Consolidated Statement of Operations. Pursuant to the requirements under the Alaska Credit Agreements, Forest Alaska entered into two floating to fixed

(9) DERIVATIVE INSTRUMENTS AND FIXED-PRICE CONTRACTS: (Continued)

interest rate swaps. In August 2007, Forest Alaska novated these interest rate swaps to Forest. The Company has maintained these interest rate swaps to fix a portion of its variable rate interest on its Credit Facility borrowings which are LIBOR based. As of December 31, 2007, we had entered into the following interest rate swaps:

	Term	Notional Amount	Floating Rate	Fixed Rate
	(Dollar Amounts in Thousands)			
Interest Rate Swap A	April 2007 – April 2010	$ 75,000	1 month LIBOR	4.80%
Interest Rate Swap B	April 2007 – April 2010	112,500	1 month LIBOR	4.96%

At December 31, 2007, the fair value of the interest rate swaps was a liability of $4.7 million, of which $2.1 million was classified as current. For the year ended December 31, 2007, the Company recorded unrealized losses related to the interest rate swaps of $4.7 million and realized gains related to the interest rate swaps of $.5 million.

In January 2008, the Company entered into a $100 million floating to fixed interest rate swap for three years commencing on June 13, 2008. The floating rate is one month LIBOR and the fixed rate is 2.75%.

Fixed-Price 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. These contracts are considered to be normal sales and, therefore, are not subject to the accounting requirement of SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities"*. The table below sets forth the relevant information regarding the fixed-price sales contracts as of December 31, 2007:

	Bbtu Per Day(1)	Weighted Average Price per MMBtu(2)
January 2008 – April 2009	15	$2.67
May 2009 – June 2011	5	3.80

(1) These volumes are based on Forest's expected share of total Netback Pool supply volumes as of December 31, 2007 and are subject to change to the extent other Netback Pool producers' dedicated Netback Pool production volumes increase or decrease disproportionately to Forest's dedicated production volumes. Changes are not expected to be material.

(2) Based on the Canadian dollar to U.S. dollar exchange rate at December 31, 2007. U.S. dollars received will fluctuate based upon foreign currency exchange rates. Changes are not expected to be material.

(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, 2007, Anschutz owned approximately 9% of Forest's outstanding common stock. Based on reports filed with the SEC, as of January 31, 2008, Anschutz has entered into forward sales contracts covering a portion of its Forest common stock, although Anschutz retains voting rights for these shares through the settlement dates.

In 1998, Forest purchased certain oil and gas assets from Anschutz, including two concessions in South Africa. Over the years, the parties have entered into agreements concerning the development of these concession blocks. In March 2003, Forest entered into a Participation Agreement regarding the development of offshore South Africa acreage, including the Ibhubesi Gas Field, with The Petroleum

(10) RELATED PARTY TRANSACTIONS: (Continued)

Oil and Gas Corporation of South Africa (Pty) Limited ("PetroSA") and Anschutz Overseas South Africa (Pty) Limited ("Anschutz Overseas"). As of February 27, 2008, 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, drilling rigs, and well equipment under the remaining terms of non-cancelable operating leases are $18.1 million, $16.6 million, $14.5 million, $14.4 million, and $13.5 million for the years ending December 31, 2008 through 2012, respectively. Future rental payments under the remaining terms of non-cancelable operating leases for fiscal periods beyond 2012 total $27.4 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 2007, $.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 $42.9 million, $27.1 million, $1.6 million, $.5 million, and $.1 million for the years ending December 31, 2008 through 2012, respectively.

Net rental payments under non-cancelable operating leases applicable to exploration and development activities and capitalized to oil and gas properties were $8.0 million in 2007, $2.2 million in 2006, and $2.8 million in 2005. Net rental payments under non-cancelable operating leases charged to expense amounted to $4.5 million in 2007, $3.5 million in 2006, and $4.3 million in 2005. 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.

(12) OTHER INCOME AND EXPENSE:

The components of other income and expense for the years ended December 31, 2007, 2006, and 2005 were as follows:

	Year Ended December 31,		
	2007	2006	2005
	(In Thousands)		
Realized foreign currency exchange gains	$ (7,721)	(315)	—
Unrealized foreign currency exchange (gain) loss	(7,694)	3,931	—
Franchise taxes	2,322	1,410	1,963
Share of (income) loss of equity method investee	(275)	(2,334)	562
Unrealized loss on other investments	4,948	—	—
Debt extinguishment costs	12,215	—	—
Other, net	(2,214)	1,135	3,722
Total other expense, net	$ 1,581	3,827	6,247

(13) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In Thousands, Except Per Share Amounts)			
2007				
Revenue	$182,609	254,669	313,025	333,589
Net earnings[1]	$ 6,891	76,799	57,987	27,629
Basic earnings per share	$ .11	1.11	.67	.32
Diluted earnings per share	.11	1.08	.65	.31
2006				
Revenue	$221,446	211,853	202,839	183,854
Net earnings[1]	$ 3,671	57,048	76,934	30,849
Basic earnings per share	$ .06	.92	1.24	.49
Diluted earnings per share	.06	.90	1.21	.48

(1) Net earnings have 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 SFAS No. 131, *"Disclosures About Segments of an Enterprise and Related Information."* At December 31, 2007, 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. The Company's remaining activities are not significant and therefore are not reported as a separate segment, but 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.

	Oil and Gas Operations			
	Year Ended December 31, 2007			
	United States	Canada	International	Total Company
	(In Thousands)			
Revenue	$ 892,818	190,263	—	1,083,081
Expenses:				
Lease operating expenses	135,983	31,490	—	167,473
Production and property taxes	51,822	3,442	—	55,264
Transportation and processing costs	9,729	10,471	—	20,200
Depletion	301,048	84,181	—	385,229
Accretion of asset retirement obligations	5,111	903	50	6,064
Earnings (loss) from operations	$ 389,125	59,776	(50)	448,851
Capital expenditures[1]	$2,807,936	173,218	15,853	2,997,007
Goodwill	$ 248,138	17,480	—	265,618

(1) Includes estimated discounted asset retirement obligations of $37.8 million related to assets placed in service during the year ended December 31, 2007.

(14) GEOGRAPHICAL SEGMENTS: (Continued)

Information for reportable segments relates to the Company's 2007 consolidated totals as follows:

	(In Thousands)
Earnings from operations for reportable segments	$ 448,851
Marketing, processing, and other	811
General and administrative expense (including stock-based compensation)	(63,751)
Interest expense	(113,162)
Administrative asset depreciation	(5,109)
Realized gains on derivative instruments, net	75,965
Unrealized losses on derivative instruments, net	(117,499)
Gain on sale of assets	7,176
Other expense, net	(1,581)
Earnings before income taxes and discontinued operations	$ 231,701

	Oil and Gas Operations			
	Year Ended December 31, 2006			
	United States	Canada	International	Total Company
	(In Thousands)			
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)]	$784,250	152,005	6,984	943,239
Goodwill	$ 71,377	14,869	—	86,246

(1) Includes estimated discounted asset retirement obligations of $2.4 million related to assets placed in service during the year ended December 31, 2006.

(14) GEOGRAPHICAL SEGMENTS: (Continued)

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 costs	(5,416)
Realized losses on derivative instruments, net	(23,864)
Unrealized gains on derivative instruments, net	83,629
Other expense, net	(3,827)
Earnings before income taxes and discontinued operations	$256,983

	Oil and Gas Operations			
	Year Ended December 31, 2005			
	United States	Canada	International	Total Company
	(In Thousands)			
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)]	$732,952	117,042	3,688	853,682
Goodwill	$ 71,377	15,695	—	87,072

(1) Includes estimated discounted asset retirement obligations of $16.3 million related to assets placed in service during the year ended December 31, 2005.

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

(14) GEOGRAPHICAL SEGMENTS: (Continued)

The following tables set forth information regarding the Company's total assets by segment and long-lived assets by geographic area:

	Total Assets		
	December 31,		
	2007	2006	2005
	(In Thousands)		
United States	$4,828,582	2,534,087	3,068,250
Canada	791,714	595,341	513,536
International	75,252	59,644	63,760
Total assets	$5,695,548	3,189,072	3,645,546

	Long-Lived Assets[(1)]		
	December 31,		
	2007	2006	2005
	(In Thousands)		
United States	$4,487,257	2,278,733	2,760,317
Canada	730,418	538,844	470,080
International	73,758	58,595	56,693
Total long-lived assets	$5,291,433	2,876,172	3,287,090

(1) Includes net property and equipment and goodwill.

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION:

Each of the Company's 8% senior notes due 2008, 8% senior notes due 2011, 7¾% senior notes due 2014, and 7¼% senior notes due 2019 are fully and unconditionally guaranteed by a wholly-owned subsidiary of the Company (the "Guarantor Subsidiary"). The Company's remaining subsidiaries (the "Non-Guarantor Subsidiaries") have not provided guarantees. Based on this distinction, the following presents condensed consolidating financial information as of December 31, 2007 and 2006 and for the three years in the period ended December 31, 2007 on an issuer (parent company), guarantor subsidiary, non-guarantor subsidiary, eliminating entries, and consolidated basis. Elimination entries presented are necessary to combine the entities.

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS

(In Thousands)

	December 31, 2007					December 31, 2006				
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS										
Current assets:										
Cash and cash equivalents	$ 1,189	386	8,110	—	**9,685**	771	126	32,267	—	**33,164**
Accounts receivable	121,698	8,979	80,890	(9,950)	**201,617**	48,010	9,428	69,709	(1,701)	**125,446**
Other current assets	140,752	273	9,047	—	**150,072**	82,227	2,380	17,783	—	**102,390**
Total current assets	263,639	9,638	98,047	(9,950)	**361,374**	131,008	11,934	119,759	(1,701)	**261,000**
Property and equipment, at cost	5,363,127	240,748	2,194,490	—	**7,798,365**	2,819,163	236,143	2,032,142	—	**5,087,448**
Less accumulated depreciation, depletion and amortization	1,852,033	82,743	837,774	—	**2,772,550**	1,605,072	63,624	628,826	—	**2,297,522**
Net property and equipment	3,511,094	158,005	1,356,716	—	**5,025,815**	1,214,091	172,519	1,403,316	—	**2,789,926**
Investment in subsidiaries	740,964	—	—	(740,964)	**—**	648,250	—	—	(648,250)	**—**
Note receivable from subsidiary	73,307	—	—	(73,307)	**—**	59,497	—	—	(59,497)	**—**
Goodwill	225,178	—	40,440	—	**265,618**	48,417	—	37,829	—	**86,246**
Due from (to) parent and subsidiaries	308,381	28,409	(336,790)	—	**—**	236,075	(16,276)	(219,799)	—	**—**
Other assets	39,424	1	3,316	—	**42,741**	43,256	1	8,643	—	**51,900**
	$5,161,987	196,053	1,161,729	(824,221)	**5,695,548**	2,380,594	168,178	1,349,748	(709,448)	**3,189,072**
LIABILITIES AND SHAREHOLDERS' EQUITY										
Current liabilities:										
Accounts payable	$ 293,523	9,810	67,706	(9,950)	**361,089**	147,397	8,394	70,843	(1,701)	**224,933**
Current portion of long-term debt	266,002	—	—	—	**266,002**	—	—	2,500	—	**2,500**
Other current liabilities	103,288	1,012	6,991	—	**111,291**	33,978	(2,111)	4,641	—	**36,508**
Total current liabilities	662,813	10,822	74,697	(9,950)	**738,382**	181,375	6,283	77,984	(1,701)	**263,941**
Long-term debt	1,373,909	—	129,126	—	**1,503,035**	748,115	—	456,594	—	**1,204,709**
Notes payable to parent	—	—	73,307	(73,307)	**—**	—	—	59,497	(59,497)	**—**
Other liabilities	136,362	1,690	50,841	—	**188,893**	57,496	1,831	35,132	—	**94,459**
Deferred income taxes	577,092	62,509	213,826	—	**853,427**	(40,398)	40,949	191,406	—	**191,957**
Total liabilities	2,750,176	75,021	541,797	(83,257)	**3,283,737**	946,588	49,063	820,613	(61,198)	**1,755,066**
Shareholders' equity	2,411,811	121,032	619,932	(740,964)	**2,411,811**	1,434,006	119,115	529,135	(648,250)	**1,434,006**
	$5,161,987	196,053	1,161,729	(824,221)	**5,695,548**	2,380,594	168,178	1,349,748	(709,448)	**3,189,072**

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(In Thousands)

	Year Ended December 31,														
	2007					2006					2005				
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$649,502	73,588	363,506	(2,704)	**1,083,892**	473,325	72,132	277,266	(2,731)	**819,992**	764,002	59,203	248,350	490	**1,072,045**
Operating expenses:															
Lease operating expenses	79,745	15,853	71,891	(16)	**167,473**	100,060	14,357	40,562	(105)	**154,874**	160,535	12,949	26,294	(17)	**199,761**
Other direct operating costs	50,651	5,475	19,338	—	**75,464**	38,219	6,315	16,383	—	**60,917**	41,807	6,001	14,306	—	**62,114**
General and administrative (including stock-based compensation)	51,022	119	12,610	—	**63,751**	40,960	182	7,166	—	**48,308**	35,130	534	8,039	—	**43,703**
Depreciation and depletion	229,069	19,186	142,094	(11)	**390,338**	140,442	19,253	107,186	—	**266,881**	259,154	21,313	88,212	—	**368,679**
Gain on sale of assets	—	—	(7,176)	—	**(7,176)**	—	—	—	—	**—**	—	—	—	—	**—**
Other operating expenses	3,844	192	2,028	—	**6,064**	10,975	127	5,078	—	**16,180**	24,412	115	3,922	—	**28,449**
Total operating expenses	414,331	40,825	240,785	(27)	**695,914**	330,656	40,234	176,375	(105)	**547,160**	521,038	40,912	140,773	(17)	**702,706**
Earnings from operations	235,171	32,763	122,721	(2,677)	**387,978**	142,669	31,898	100,891	(2,626)	**272,832**	242,964	18,291	107,577	507	**369,339**
Equity earnings in subsidiaries	2,119	—	—	(2,119)	**—**	85,360	—	—	(85,360)	**—**	(10,036)	—	—	10,036	**—**
Other income and expense:															
Interest expense	74,727	9	54,727	(16,301)	**113,162**	61,673	111	19,457	(9,454)	**71,787**	61,350	1,444	6,699	(8,090)	**61,403**
Unrealized losses (gains) on derivative instruments, net	69,053	11,318	37,128	—	**117,499**	(67,022)	(20,241)	3,634	—	**(83,629)**	18,138	1,474	1,761	—	**21,373**
Realized (gains) losses on derivative instruments, net	(61,303)	(4,137)	(10,525)	—	**(75,965)**	18,326	6,787	(1,249)	—	**23,864**	21,237	2,259	11,894	—	**35,390**
Other (income) expense, net	(73,811)	755	(6,267)	80,904	**1,581**	(9,820)	696	(49)	13,000	**3,827**	(76,059)	388	(14,037)	95,955	**6,247**
Total other income and expense	8,666	7,945	75,063	64,603	**156,277**	3,157	(12,647)	21,793	3,546	**15,849**	24,666	5,565	6,317	87,865	**124,413**
Earnings before income taxes and discontinued operations	228,624	24,818	47,658	(69,399)	**231,701**	224,872	44,545	79,098	(91,532)	**256,983**	208,262	12,726	101,260	(77,322)	**244,926**
Income tax expense (benefit)	59,318	9,242	(6,165)	—	**62,395**	56,370	18,344	16,189	—	**90,903**	56,694	5,443	32,810	(1,589)	**93,358**
Earnings from continuing operations	169,306	15,576	53,823	(69,399)	**169,306**	168,502	26,201	62,909	(91,532)	**166,080**	151,568	7,283	68,450	(75,733)	**151,568**
Income from discontinued operations, net of tax	—	—	—	—	**—**	—	—	2,422	—	**2,422**	—	—	—	—	**—**
Net earnings	$169,306	15,576	53,823	(69,399)	**169,306**	$168,502	26,201	65,331	(91,532)	**168,502**	$151,568	7,283	68,450	(75,733)	**151,568**

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

(In Thousands)

	Year Ended December 31,											
	2007				2006				2005			
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidated
Operating activities:												
Net earnings	$ 99,907	15,576	53,823	**169,306**	76,970	26,201	65,331	**168,502**	75,835	7,283	68,450	**151,568**
Adjustments to reconcile net earnings to net cash provided by operating activities:												
Depreciation and depletion	229,069	19,186	142,083	**390,338**	140,442	19,253	107,186	**266,881**	259,154	21,313	88,212	**368,679**
Unrealized losses (gains) on derivative instruments, net	69,053	11,318	37,128	**117,499**	(67,022)	(20,241)	3,634	**(83,629)**	18,138	1,474	1,761	**21,373**
Deferred income tax expense (benefit)	53,192	9,242	(6,038)	**56,396**	54,384	18,344	17,276	**90,004**	53,434	5,443	30,983	**89,860**
Other, net	14,154	192	(5,907)	**8,439**	24,357	127	9,350	**33,834**	3,117	115	18,883	**22,115**
Changes in operating assets and liabilities, net of effects of acquisitions and divestitures:												
Accounts receivable	6,825	449	(6,921)	**353**	8,200	1,511	(10,351)	**(640)**	10,150	(3,706)	(21,794)	**(15,350)**
Other current assets	(3,250)	2,107	2,700	**1,557**	(32,109)	(2,105)	(5,646)	**(39,860)**	(26,169)	3,233	(2,922)	**(25,858)**
Accounts payable	4,091	1,856	(15,539)	**(9,592)**	(5,791)	(3,098)	18,089	**9,200**	66,774	2,248	(59,494)	**9,528**
Accrued interest and other current liabilities	(3,226)	(207)	(22,618)	**(26,051)**	(18,791)	1,650	(4,673)	**(21,814)**	(25,523)	30	32,143	**6,650**
Net cash provided by operating activities	469,815	59,719	178,711	**708,245**	180,640	41,642	200,196	**422,478**	434,910	37,433	156,222	**628,565**
Investing activities:												
Acquisition of Houston Exploration, net of cash acquired	(775,365)	—	—	**(775,365)**	—	—	—	**—**	—	—	—	**—**
Capital expenditures for property and equipment	(423,526)	(30,605)	(365,773)	**(819,904)**	(573,602)	(32,366)	(310,430)	**(916,398)**	(256,341)	(29,271)	(405,105)	**(690,717)**
Proceeds from sale of Alaska Assets	400,000	—	—	**400,000**	—	—	—	**—**	—	—	—	**—**
Other, net	5,857	26,161	70,030	**102,048**	1,074	357	5,076	**6,507**	6,720	8,210	4,557	**19,487**
Net cash used by investing activities	(793,034)	(4,444)	(295,743)	**(1,093,221)**	(572,528)	(32,009)	(305,354)	**(909,891)**	(249,621)	(21,061)	(400,548)	**(671,230)**
Financing activities:												
Proceeds from bank borrowings	1,308,000	—	228,526	**1,536,526**	1,398,102	—	164,676	**1,562,778**	850,000	—	56,741	**906,741**
Repayments of bank borrowings	(1,342,885)	—	(199,178)	**(1,542,063)**	(1,296,000)	—	(136,574)	**(1,432,574)**	(905,000)	—	(35,000)	**(940,000)**
Issuance of 7¼% senior notes, net of issuance costs	739,176	—	—	**739,176**	—	—	—	**—**	—	—	—	**—**
Repayments of Alaska Credit Agreements	—	—	(375,000)	**(375,000)**	—	—	—	**—**	—	—	—	**—**
Proceeds from Alaska Credit Agreements, net of issuance costs	—	—	—	**—**	—	—	367,706	**367,706**	—	—	—	**—**
Net activity in investments of subsidiaries	(389,846)	(55,578)	445,424	**—**	264,058	(10,109)	(253,949)	**—**	(179,005)	(16,373)	195,378	**—**
Other, net	9,192	563	(8,842)	**913**	24,537	602	(9,217)	**15,922**	43,377	—	(14,714)	**28,663**
Net cash provided (used) by financing activities	323,637	(55,015)	90,930	**359,552**	390,697	(9,507)	132,642	**513,832**	(190,628)	(16,373)	202,405	**(4,596)**
Effect of exchange rate changes on cash	—	—	1,945	**1,945**	—	—	(486)	**(486)**	—	—	(759)	**(759)**
Net increase (decrease) in cash and cash equivalents	418	260	(24,157)	**(23,479)**	(1,191)	126	26,998	**25,933**	(5,339)	(1)	(42,680)	**(48,020)**
Cash and cash equivalents at beginning of period	771	126	32,267	**33,164**	1,962	—	5,269	**7,231**	7,301	1	47,949	**55,251**
Cash and cash equivalents at end of period	$ 1,189	386	8,110	**9,685**	771	126	32,267	**33,164**	1,962	—	5,269	**7,231**

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

The following information is presented in accordance with SFAS No. 69, *"Disclosures about Oil and Gas Producing Activities"*.

(A) Costs Incurred in Oil and Gas Acquisition, Exploration, and Development Activities. The following costs were incurred in oil and gas acquisition, exploration, and development activities during the years ended December 31, 2007, 2006, and 2005:

	United States	Canada	International	Total
		(In Thousands)		
2007				
Property acquisition costs:				
Proved properties	$1,744,087	6	—	1,744,093
Unproved properties	449,346	—	—	449,346
Exploration costs	96,483	35,861	15,853	148,197
Development costs	518,020	137,351	—	655,371
Total costs incurred[1]	$2,807,936	173,218	15,853	2,997,007
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]	$ 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

(1) Includes amounts relating to estimated asset retirement obligations of $37.8 million, $2.4 million, and $16.3 million for assets placed in service in the years ended December 31, 2007, 2006, and 2005, respectively.

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

	2007	2006	2005
		(In Thousands)	
Costs related to proved properties	$ 7,157,249	4,751,171	5,957,805
Costs related to unproved properties	568,510	261,259	275,684
	7,725,759	5,012,430	6,233,489
Less accumulated depletion	(2,742,539)	(2,265,018)	(3,059,031)
	$ 4,983,220	2,747,412	3,174,458

(16) 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, 2007, 2006, and 2005 are presented below.

	United States	Canada	Total
		(In Thousands)	
2007			
Oil and gas sales	$892,818	190,263	1,083,081
Expenses:			
Production expense	197,534	45,403	242,937
Depletion expense	301,048	84,181	385,229
Accretion of asset retirement obligations	5,111	903	6,014
Income tax expense	139,696	16,486	156,182
Total expenses	643,389	146,973	790,362
Results of operations from producing activities	$249,429	43,290	292,719
Depletion rate per Mcfe	$ 2.42	2.68	2.47
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

(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 2007, 2006, and 2005 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.

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

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	Italy	Total	United States	Canada	Italy	Total	Total MMcfe
Balance at January 1, 2005	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	(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
Revisions of previous estimates	(836)	(357)	—	(1,193)	(21,202)	(12,837)	—	(34,039)	(41,197)
Extensions and discoveries	10,981	3,041	—	14,022	202,349	48,171	56,308	306,828	390,960
Production	(6,885)	(1,060)	—	(7,945)	(82,963)	(25,079)	—	(108,042)	(155,712)
Sales of reserves in place	(29,749)	—	—	(29,749)	(7,983)	—	—	(7,983)	(186,477)
Purchases of reserves in place	6,477	—	—	6,477	617,573	—	—	617,573	656,435
Balance at December 31, 2007	87,157	7,319	—	94,476	1,287,870	208,198	56,308	1,552,376	2,119,232
Proved developed reserves at:									
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
December 31, 2007	61,650	4,947	—	66,597	900,483	163,438	28,154	1,092,075	1,491,657

(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%.

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

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the estimated future pretax net cash flows relating to proved oil and natural gas reserves, less the tax bases of the properties involved. The future income tax expenses give effect to tax credits and allowances, but do not reflect the impact of general and administrative and interest expense.

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, 2007			
	United States	Canada	Italy	Total
	(In Thousands)			
Future oil and gas sales	$14,248,411	1,850,767	957,010	17,056,188
Future production costs	(3,249,115)	(410,650)	(71,658)	(3,731,423)
Future development costs	(1,086,890)	(141,838)	(37,067)	(1,265,795)
Future income taxes	(2,504,853)	(277,975)	(348,467)	(3,131,295)
Future net cash flows	7,407,553	1,020,304	499,818	8,927,675
10% annual discount for estimated timing of cash flows	(3,790,817)	(388,956)	(208,767)	(4,388,540)
Standardized measure of discounted future net cash flows	$ 3,616,736	631,348	291,051	4,539,135

	December 31, 2006			
	United States	Canada	Italy	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

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

	December 31, 2005			
	United States	Canada	Italy	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

(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, 2007			
	United States	Canada	Italy	Total
	(In Thousands)			
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$2,143,861	450,503	—	2,594,364
Changes resulting from:				
Sales of oil and gas, net of production costs	(695,321)	(144,860)	—	(840,181)
Net changes in prices and future production costs	1,258,999	171,640	—	1,430,639
Net changes in future development costs	(78,440)	5,576	—	(72,864)
Extensions, discoveries, and improved recovery	445,794	115,047	481,250	1,042,091
Development costs incurred during the period	399,218	54,296	—	453,514
Revisions of previous quantity estimates	(85,383)	(48,806)	—	(134,189)
Changes in production rates and other	6,889	(2,197)	—	4,692
Sales of reserves in place	(871,495)	—	—	(871,495)
Purchases of reserves in place	1,369,079	—	—	1,369,079
Accretion of discount on reserves at beginning of year before income taxes	268,804	57,650	—	326,454
Net change in income taxes	(545,269)	(27,501)	(190,199)	(762,969)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$3,616,736	631,348	291,051	4,539,135

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2007 was based on weighted average year-end spot natural gas prices of approximately $6.20 per Mcf in the United States, approximately $6.12 per Mcf in

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

Canada, and $17.00 per Mcf in Italy, and on weighted average year-end spot liquids prices of approximately $71.89 per barrel in the United States and approximately $78.71 per barrel in Canada.

	December 31, 2006			
	United States	Canada	Italy	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	(1,245,361)	(241,144)	—	(1,486,505)
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
Changes in production rates and other	(454,458)	(45,975)	—	(500,433)
Sales of reserves in place	(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

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

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

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	Italy	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	1,539,485	217,937	—	1,757,422
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
Changes in production rates and other	(124,669)	(11,437)	—	(136,106)
Sales of reserves in place	(44,100)	—	—	(44,100)
Purchases of reserves in place	298,189	9,186	—	307,375
Accretion of discount on reserves at beginning of year before income taxes	296,413	34,730	—	331,143
Net change in income taxes	(607,237)	(98,925)	—	(706,162)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$3,339,202	513,423	—	3,852,625

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2005 was based on 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.

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 Securities Exchange Act of 1934 (i) is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms; and (ii) is accumulated and communicated to Forest's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

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, 2007 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, 2007. The effectiveness of our internal control over financial reporting as of December 31, 2007 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 Forest Oil Corporation's internal control over financial reporting as of December 31, 2007, 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 included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, 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, Forest Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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 sheets of Forest Oil Corporation and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for the years then ended and our report dated February 27, 2008 expressed an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
February 27, 2008

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, 2007 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, 2007 and 2006
3. Consolidated Statements of Operations—Years Ended December 31, 2007, 2006, and 2005
4. Consolidated Statements of Shareholders’ Equity—Years Ended December 31, 2007, 2006, and 2005
5. Consolidated Statements of Cash Flows—Years Ended December 31, 2007, 2006, and 2005
6. Notes to Consolidated Financial Statements—Years Ended December 31, 2007, 2006, and 2005

(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 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 Registration Statement on Form S-4 dated February 6, 2002 (File No. 333-82254).
4.3	Indenture dated as of April 25, 2002 between Forest Oil Corporation and State Street Bank and Trust Company, incorporated herein by reference to Exhibit 4.6 to Forest Oil Corporation Registration Statement on Form S-4 dated June 11, 2002 (File No. 333-90220).
4.4	Indenture dated as of June 6, 2007 between Forest Oil Corporation and U.S. Bank National Association, incorporated herein by reference to Exhibit 4.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
4.5	Registration Rights Agreement, dated as of July 10, 2000, by and between Forest Oil Corporation and the other signatories thereto, incorporated herein by reference to Exhibit 4.15 to Forest Oil Corporation Registration Statement on Form S-4, dated November 6, 2000 (File No. 333-49376).
4.6	Registration Rights Agreement between Forest Oil Corporation and the other signatories thereto dated as of June 6, 2007, incorporated herein by reference to Exhibit 4.2 to Form 10-Q for Forest Oil Corporation for the quarterly period ended June 30, 2007 (File No. 001-13515).
4.7	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 Form 8-K for Forest Oil Corporation, dated October 17, 2003 (File No. 001-13515).

Exhibit Number	Description
4.8	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).
4.9	U.S. Credit Agreement—Second Amended and Restated Credit Agreement dated as of June 6, 2007 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, BMO Capital Markets Financing, Inc., Credit Suisse, Cayman Islands Branch, and Deutsche Bank Securities, Inc., as Co-U.S. Documentation Agents, and JPMorgan Chase Bank, N.A., as Global Administrative Agent, incorporated herein by reference to Exhibit 4.4 to Form 10-Q for Forest Oil Corporation dated August 9, 2007 (File No. 001-13515).
4.10	Canadian Credit Agreement—Second Amended and Restated Credit Agreement dated as of June 6, 2007 among Canadian Forest Oil Ltd., each of the lenders party thereto, Bank of America, N.A. and Citibank, N.A., as Co-Global Syndication 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 4.5 to Form 10-Q for Forest Oil Corporation dated August 9, 2007 (File No. 001-13515).
10.1*	Forest Oil Corporation 1996 Stock Incentive Plan and Option Agreement, incorporated herein by reference to Exhibit 4.1 to Registration Statement on 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 Registration Statement on 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*	Amendment No. 4 to Forest Oil Corporation 2001 Stock Incentive Plan dated June 5, 2007, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation dated November 8, 2007 (File No. 001-13515).

Exhibit Number	Description
10.10*	Form of Employee Stock Option Agreement, incorporated herein by reference to Exhibit 4.2 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.11*	Form of Non-Employee Director Stock Option Agreement, incorporated herein by reference to Exhibit 4.3 to Registration Statement on Form S-8 for Forest Oil Corporation dated June 6, 2001 (File No. 333-62408).
10.12*	Form of Restricted Stock Agreement, incorporated herein by reference to Exhibit 10.6 to Form 10-Q for Forest Oil Corporation dated November 9, 2004 (File No. 001-13515).
10.13*	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).
10.14*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2001 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation dated August 9, 2007 (File No. 001-13515).
10.15*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2001 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation dated August 9, 2007 (File No. 001-13515).
10.16*	Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Annex E to Forest Oil Corporation's Registration Statement on Form S-4, dated April 30, 2007 (File No. 333-140532).
10.17*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation dated August 9, 2007 (File No. 001-13515).
10.18*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation dated August 9, 2007 (File No. 001-13515).
10.19*	Form of Severance Agreement for Grandfathered Executive Officer, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.20*	Form of Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.21*	Form of Severance Agreement for Vice President, incorporated herein by reference to Exhibit 10.3 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.22*	Form of Severance Agreement for Grandfathered Vice President, incorporated herein by reference to Exhibit 10.4 to Form 8-K for Forest Oil Corporation dated December 17, 2007 (File No. 001-13515).
10.23*	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 dated November 14, 2002 (File No. 001-13515).
10.24*	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 dated August 9, 2005 (File No. 001-13515).

Exhibit Number	Description
10.25*	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 dated August 9, 2006 (File No. 001-13515).
10.26*	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 dated November 13, 2003 (File No. 001-13515).
10.27*	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).
10.28*	Amendment to Forest Oil Corporation Salary Deferral Deferred Compensation Plan dated August 30, 2007, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation dated November 8, 2007 (File No. 001-13515).
10.29*	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).
10.30*	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).
10.31*	Amendment to Forest Oil Corporation Amended and Restated 2005 Salary Deferred Compensation Plan dated August 30, 2007, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation dated November 8, 2007 (File No. 001-13515).
10.32*	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).
10.33*	Forest Oil Corporation Executive Deferred Compensation Plan as Amended and Restated, effective as of January 1, 2005, incorporated by reference to Form 10-K for Forest Oil Corporation for the year ended December 31, 2006 (File No. 001-13515).
10.34*	First Amendment to Forest Oil Corporation Executive Deferred Compensation Plan as Amended and Restated Effective as of January 1, 2005, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation dated November 8, 2007 (File No. 001-13515).
10.35*†	Forest Oil Corporation 2008 Annual Incentive Plan.
10.36*	Forest Oil Corporation 2007 Annual Incentive Plan, as revised on October 24, 2007, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated October 25, 2007 (File No. 001-13515).
10.37	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).
10.38	Standstill Agreement dated January 7, 2007, between Forest Oil Corporation and JANA Partners LLC, incorporated herein by reference to Exhibit 4.13 to Forest Oil Corporation Registration Statement on Form S-4 (File No. 333-140532).
10.39	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 dated November 9, 2005 (No. 001-13515).

Exhibit Number	Description
10.40	Membership Interest Purchase Agreement dated as of May 24, 2007, among Forest Alaska Operating LLC, Forest Oil Corporation, and Pacific Energy Resources Ltd., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 28, 2007 (File No. 001-13515).
10.41	Asset Sales Agreement dated as of May 24, 2007, between Forest Oil Corporation and Pacific Energy Resources Ltd., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated May 28, 2007 (File No. 001-13515).
10.42	Amendment No. 1 to Membership Interest Purchase Agreement dated July 31, 2007, among Forest Alaska Holding LLC, Forest Alaska Operating LLC, Forest Oil Corporation, and Pacific Energy Resources Ltd., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated July 31, 2007 (File No. 001-13515).
10.43	Amendment No. 1 to Asset Sales Agreement dated July 31, 2007, between Forest Oil Corporation and Pacific Energy Resources Ltd., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated July 31, 2007 (File No. 001-13515).
14.1†	Forest Oil Corporation Proper Business Practices Policy Revised as of January 21, 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.
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, 2008

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, 2007, 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, 2008
/s/ DAVID H. KEYTE David H. Keyte	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2008
/s/ VICTOR A. WIND Victor A. Wind	Corporate Controller (Principal Accounting Officer)	February 28, 2008
/s/ FORREST E. HOGLUND Forrest E. Hoglund	Chairman of the Board	February 28, 2008
/s/ WILLIAM L. BRITTON William L. Britton	Director	February 28, 2008
/s/ LOREN K. CARROLL Loren K. Carroll	Director	February 28, 2008
/s/ DOD. A. FRASER Dod. A. Fraser	Director	February 28, 2008
/s/ JAMES H. LEE James H. Lee	Director	February 28, 2008
/s/ JAMES D. LIGHTNER James D. Lightner	Director	February 28, 2008
/s/ PATRICK R. MCDONALD Patrick R. McDonald	Director	February 28, 2008

Index to Exhibits

Exhibit Number	Description
10.35	Forest Oil Corporation 2008 Annual Incentive Plan.
14.1	Forest Oil Corporation Proper Business Practices Policy Revised as of January 21, 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

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

BNY Mellon Shareowner Services
480 Washington Boulevard
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.bnymellon.com/shareowner/isd

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 3600
Denver, Colorado 80202
Thursday, May 8, 2008 at 9:00 a.m. (MDT)

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.

NON-GAAP FINANCIAL MEASURES

In this annual report, Forest has reported net earnings adjusted for certain items, a non-GAAP financial measure, which facilitates comparisons to earnings forecasts prepared by stock analysts and other third parties. Such forecasts generally exclude the effects of items that are difficult to predict or to measure in advance and are not directly related to Forest's ongoing operations. Net earnings excluding the effects of certain items should not be considered a substitute for net earnings as reported in accordance with GAAP.
Forest reported adjusted EBITDA, which consists of net earnings plus income tax expense—discontinued operations, income tax expense—continuing operations, unrealized losses (gains) on derivative instruments, net, unrealized foreign currency exchange (gains) losses, unrealized losses on other investments, realized foreign currency exchange gains, interest expense, write-off of unamortized debt costs and prepayment premiums, accretion of asset retirement obligations, depreciation and depletion, impairments and stock-based compensation. Forest further reported adjusted discretionary cash flow, which consists of adjusted EBITDA minus interest expense, write-off of unamortized debt costs and prepayment premiums, current income tax benefit (expense) and other non-cash items. Management uses adjusted EBITDA and adjusted discretionary cash flow as measures of operational performance. Adjusted EBITDA and adjusted discretionary cash flow should not be considered as alternatives to net earnings as reported under GAAP.
Forest reported total cash costs as a non-GAAP measure calculated in accordance with oil and gas industry standards that is used by management to assess the cash operating performance. Total cash costs is defined as all cash operating costs, including production expense, general and administrative expense (excluding stock-based compensation), interest expense and current income tax (benefit) expense.

All-Sources Reserve Replacement Ratio

Forest all-sources reserve replacement ratio of 703% was calculated by dividing the sum of total estimated proved reserve additions, 1,047 Bcfe, by 2007 net sales volumes of 149 Bcfe.

FD&A Costs

Forest FD&A costs of $2.27 per Mcfe were calculated by dividing the sum of total exploration, development, and acquisition costs, $2.375 billion, by the sum of total additions to estimated proved reserves during 2007 of 1,047 Bcfe.

Organic Reserve Replacement Ratio

Forest organic reserve replacement ratio of 236% was calculated by dividing the sum of total additions to estimated proved reserves during 2007, including revisions and excluding purchases of properties of 352 Bcfe, by 2007 net sales volumes of 149 Bcfe.

Organic F&D Costs

Forest organic F&D costs of $2.21 per Mcfe were calculated by dividing the sum of total exploration and development costs, $777 million, by the sum of total additions to estimated proved reserves during 2007, including revisions and excluding purchases of properties of 352 Bcfe.

The reconciliation of net earnings adjusted for certain items, adjusted EBITDA, adjusted discretionary cash flow and total cash costs to their most comparable GAAP measures and the estimated proved reserve information are presented in Forest's February 21, 2008 year-end press release, which can be viewed at www.forestoil.com.

FORWARD-LOOKING STATEMENTS

This report includes 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 2007 10-K for additional disclosures.

FOREST OIL CORPORATION • 707 SEVENTEENTH STREET, SUITE 3600 • DENVER, COLORADO 80202

303.812.1400 • www.forestoil.com