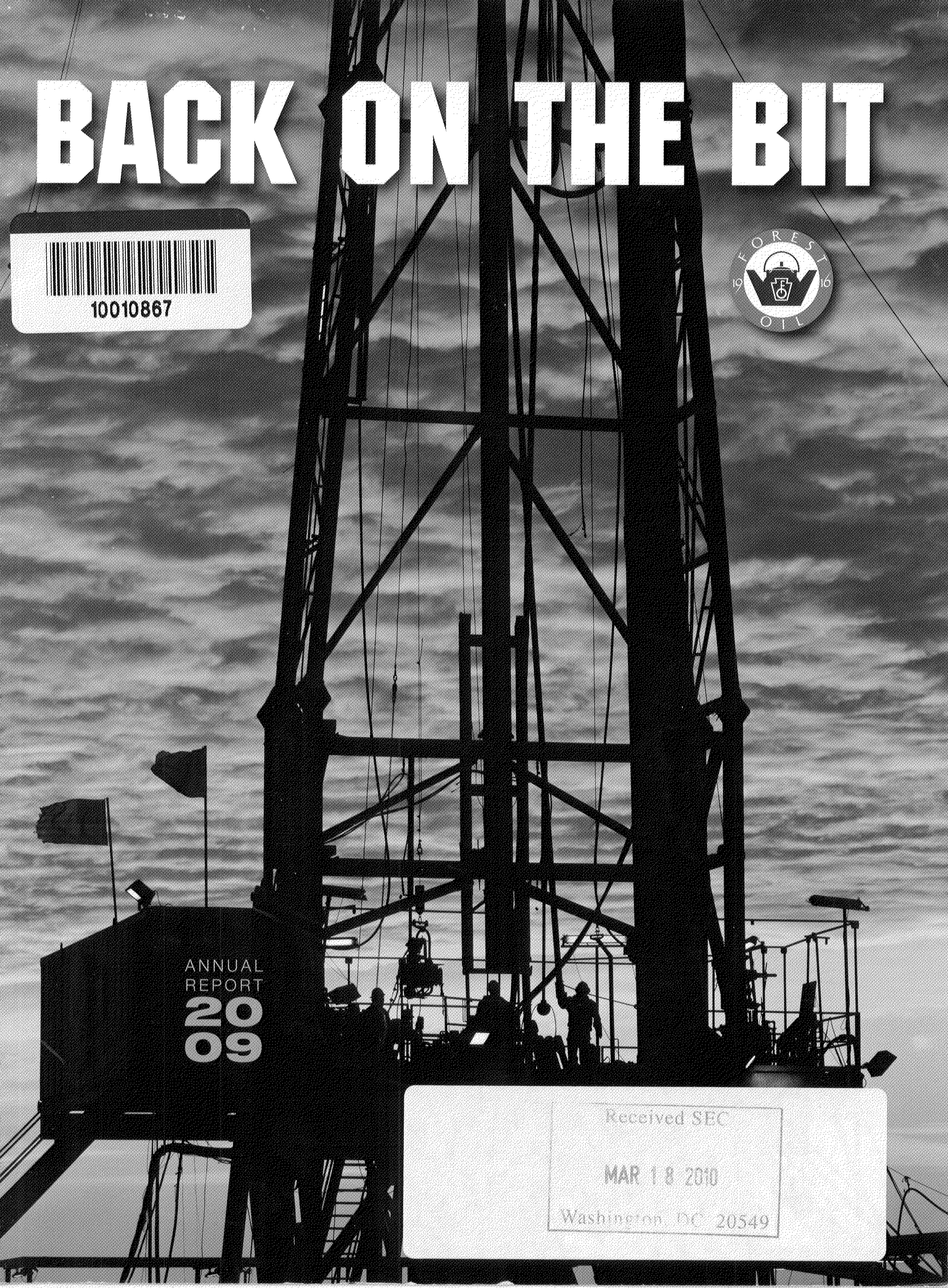
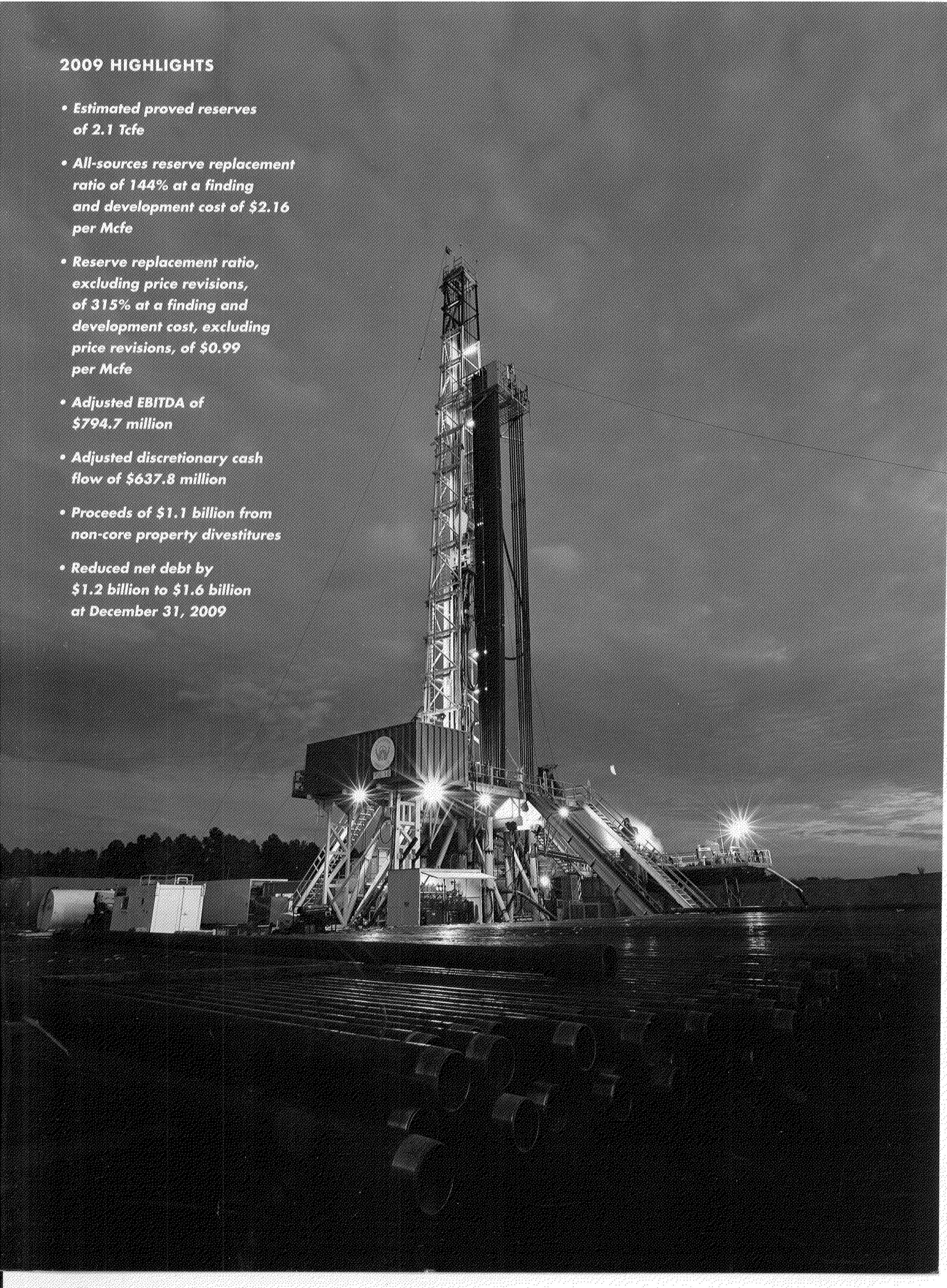
BACK ON THE BIT



2009 HIGHLIGHTS

- *Estimated proved reserves of 2.1 Tcfe*
- *All-sources reserve replacement ratio of 144% at a finding and development cost of $2.16 per Mcfe*
- *Reserve replacement ratio, excluding price revisions, of 315% at a finding and development cost, excluding price revisions, of $0.99 per Mcfe*
- *Adjusted EBITDA of $794.7 million*
- *Adjusted discretionary cash flow of $637.8 million*
- *Proceeds of $1.1 billion from non-core property divestitures*
- *Reduced net debt by $1.2 billion to $1.6 billion at December 31, 2009*



Dear Fellow Shareholders

2009, not unlike 2008, challenged the oil and gas industry and the overall economy. Although the global financial markets stabilized in 2009, almost every segment of the economy has now experienced a boom-to-bust scenario. Oil and gas commodity prices collapsed during the year, but improved at year end as our industry recovered. Due to historic volatility in commodity prices, most exploration and production companies slowed capital spending and focused on improving their balance sheets. Forest was no exception, reducing our net debt by $1.2 billion, largely as a result of approximately $1.1 billion of non-core property divestitures. This move significantly improved our balance sheet, resulting in us moving "back on the bit" in 2010. Through these tough times, Forest's strategy has never wavered:

1. ***Focus On "Profitable" Organic Growth***
   Organic reserve and production growth with attractive economic returns is the top priority at Forest. During 2009, our capital spending behavior was driven primarily by our expectation of lower natural gas prices, along with projections for service costs to decrease throughout the year. To benefit our shareholders, Forest chose to defer growth in 2009 because of the disconnect between costs and commodity prices. As costs and commodity prices have now stabilized, Forest intends to increase drill bit spending in 2010, yielding double-digit organic growth and profitable economic returns, thanks to a focused, high-quality asset base.

2. ***Cost Control***
   Forest has built a reputation as a low-cost operator, one of the lowest in the industry year after year. We scrutinize all costs throughout the organization, from drilling costs to general and administrative expenses. Our cost focus and associated improvements over the past several years allowed us to extract margin from the value chain, when top-line growth was uncertain. Costs are of increasing importance in resource plays where "manufacturing" repeatability is imperative to economically extract the resource potential. Forest intends to maintain this cost focus in 2010 with a forecasted 5% reduction in production expense.

3. ***Manage The Portfolio***
   As a result of our transactions, Forest now has the asset portfolio we desire. Our core properties are in the Texas Panhandle, East Texas/North Louisiana and the Deep Basin in Canada. Through the sale of the Permian Basin and other non-core properties in 2009 for approximately $1.1 billion, which represented 12% of Forest's total production, we have essentially sold all of the producing fields from the company we inherited in August 2003. With every transaction, whether a purchase or sale, we have upgraded the quality of our asset base. We will continue to upgrade the portfolio through bolt-on acquisitions and additional non-core asset divestitures.

4. *Financial Flexibility*
   Forest maintained adequate liquidity throughout 2009; however, the absolute level of debt was high due to acquisition activity in 2008. We exceeded expectations in the amount and timing of our debt reduction in 2009, and we now enjoy new levels of financial strength and flexibility as we enter 2010. Forest plans to maintain its current range of debt compared to proved reserves, as this provides a prudent capital structure at this point in the commodity price cycle.

2009 RESULTS

Our expectations for lower commodity prices and eventual service cost reductions came to pass in 2009. As a result, Forest entered into commodity price hedges that provided price protection for 53% of our production. Through our effective cost-reduction initiatives, we were able to lower production expense for the fourth consecutive year. Although the Company reduced spending in 2009, we achieved numerous milestones throughout the organization.

First and foremost, we replaced 315% of production organically at one of the lowest finding costs in our history. This was achieved through a drilling program designed to delineate our core areas. These results are a testament to our high-quality portfolio and bode well for our future activity.

Second, we performed thorough reviews of our assets to comparatively determine their future growth potential and prospectivity. These field studies highlighted the value and inventory of Forest's core asset holdings, while further creating value in the context of our 2009 divestiture program. Fields were selected for retention or sale based on these studies. A further benefit was that we identified vast horizontal drilling opportunities across our asset base in both tight-gas sands and shales.

2010 PLAN

As a result of significantly increased liquidity, stabilized commodity prices and lower costs, Forest will be "back on the bit" in 2010. Our capital program of $600–700 million, which is budgeted to be within a reasonable level of cash flow, is expected to yield organic production growth of 10-12%. We will direct approximately two-thirds of our spending to horizontal wells. Our portfolio is focused, yet diverse enough to allow capital allocation to our most successful growth areas. Our capital budget also includes spending on land and the development of new resource plays. We follow three sequential steps to identify and exploit a resource play:

1. **VALIDATE** the concept and well performance through testing, including core analysis and vertical well testing.

2. **EXECUTE** on the initial wells in terms of cost control and mechanical and completion success.

3. **FULL DEVELOPMENT** begins only after the first two steps are successful and provides for future success over an entire area by proving-up a conservative "mid-case" that we then use in our economic assumptions.

Our 2009 field studies and work program advanced our three primary resource plays in the Texas Panhandle, East Texas/North Louisiana and the Deep Basin in Canada. Approximately 75% of our spending in 2010 will be in these areas. These plays possess thick gas-charged columns of tight-gas sands and shales that are remarkably similar in terms of exploitation techniques.

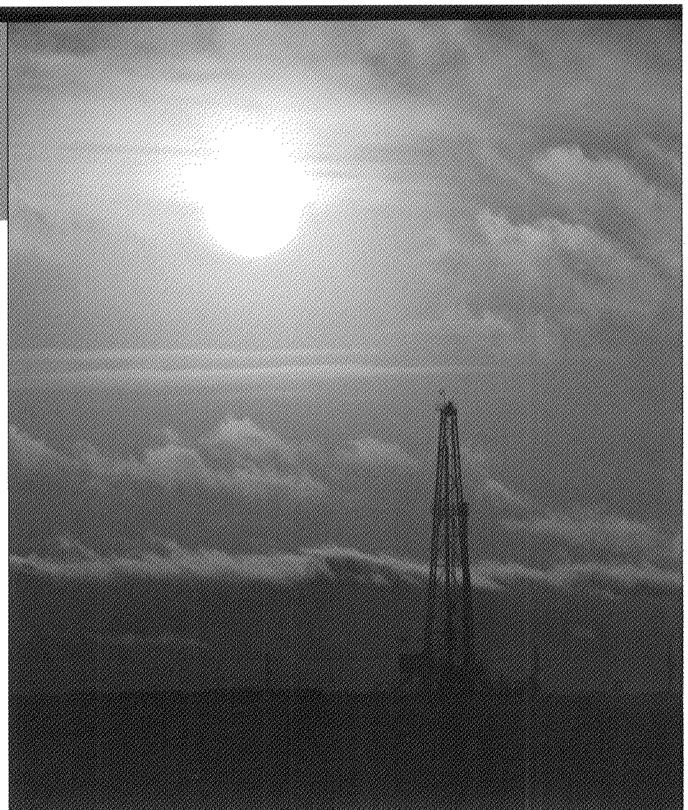
Michael N. Kennedy	John C. Ridens	H. Craig Clark	James D. Lightner
Executive Vice President & CFO	Executive Vice President & COO	President & CEO	Chairman of the Board

In closing, we would like to welcome Ray Wilcox to our Board of Directors. His extensive experience in the oil and gas industry is a valued addition to our Board. We also want to thank our shareholders and hard-working employees. Our employees are all shareholders and receive the same types of benefits and incentives as management. We look forward to an excellent 2010 as we move "back on the bit."

JAMES D. LIGHTNER
Chairman of the Board

H. CRAIG CLARK
President and Chief Executive Officer

Operations



All of Forest's core areas consist of tight-gas sand and shale plays in North America with a multitude of stacked pay opportunities. Forest initially exploited these pay intervals through vertical development, but as drilling and completion technology advanced, Forest transitioned the development of these plays from vertical to horizontal development. Through the application of horizontal drilling, Forest is able to enhance initial production rates and estimated ultimate recoveries while focusing on reducing ultimate drilling costs. Forest's three core assets are the Granite Wash play in the Texas Panhandle, the Haynesville/Bossier Shales and Cotton Valley Sands plays in East Texas/North Louisiana, and the Cretaceous/Nikanassin play in Canada. We expect that these core areas will be primarily responsible for Forest's organic growth in 2010 and will consume the majority of the Company's capital expenditures. In 2010, Forest intends to organically grow production from the portfolio at a double-digit percentage rate and reduce the overall operational costs of the organization.

GRANITE WASH

GROSS ACREAGE POSITION	135,000
NET ACREAGE POSITION	94,000

Although Forest has been testing and planning horizontal drilling for several years, 2009 was the year the Texas Panhandle horizontal program moved to the forefront. Forest and other operators posted impressive initial production rates and improved estimated ultimate recoveries. In particular, Forest drilled four horizontal wells in a Granite Wash formation that yielded an average 24-hour initial production rate of 30 MMcfe/d. Notably, approximately 60% of this rate was from liquids. With the favorable price of oil and natural gas liquids relative to natural gas, this liquids-rich play provides superior rates of return compared to other natural gas plays in North America. Forest expects to run three of its own Lantern Drilling rigs to drill approximately 20 horizontal wells in the Granite Wash portion of the play in Wheeler and Hemphill Counties, Texas, in 2010. Additionally, Forest intends to run a fourth rig in Lipscomb, Roberts and northwestern Hemphill Counties in an effort to expand an attractive horizontal drilling play in the Lower Morrow and other formations. In 2009, Forest tested a horizontal well in the Lower Morrow at a 24-hour initial production rate of 20 MMcfe/d. Other objectives present in the area are the Douglas, Cleveland, Tonkawa, Novi-Lime and the Atoka. As drilling in this area progresses, we expect it to become a larger contributor to growth for the Company.

HAYNESVILLE/BOSSIER SHALES AND COTTON VALLEY SANDS

GROSS ACREAGE POSITION	198,000
NET ACREAGE POSITION	154,000

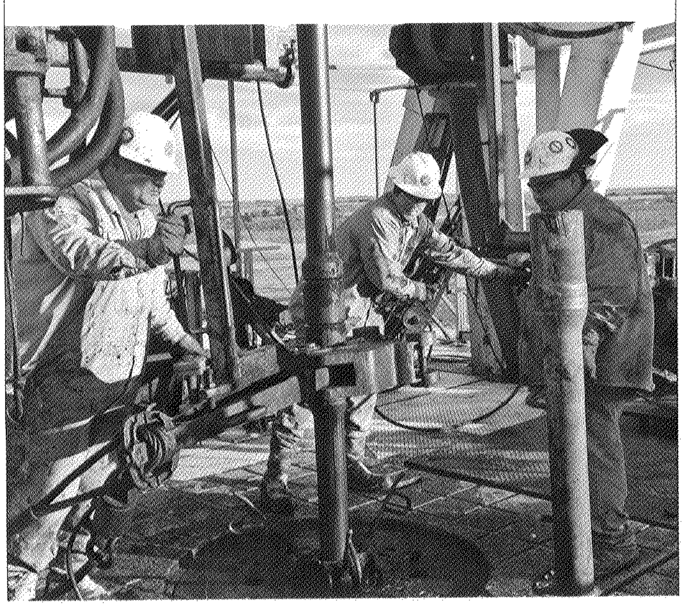
Forest's 2009 drilling activities on its significant acreage position in the Haynesville and Bossier Shales yielded several high production rate wells and helped to further refine our drilling and completion techniques. Forest drilled four wells on its northern Louisiana acreage that had average 24-hour initial production rates of 18 MMcfe/d. Forest intends to increase its rig count in the Haynesville/Bossier Shales in northern Louisiana to three rigs for 2010 and drill 12 to 16 wells. The program will consist primarily of development drilling in Red River Parish, where consistent results have been delivered, and delineation drilling in Sabine Parish. Forest's key 2010 Haynesville and Bossier Shale goal is to reduce total drilling days and thereby reduce drilling costs, while still generating wells with high production rates per foot of lateral drilled.

In East Texas, Forest plans to run one rig to test the Haynesville and Bossier Shales and to continue its successful horizontal drilling program in the Cotton Valley Sands. First, Forest intends to utilize the expertise gained from its successful Haynesville and Bossier Shales drilling program in North Louisiana, along with emerging Bossier Shale industry activity in East Texas, to test the Haynesville/Bossier Shales in East Texas in 2010. Second, given the successful horizontal drilling of Cotton Valley wells since the inception of its horizontal program in 2007, Forest intends to further this delineation program. With further drilling and completion enhancements, Forest expects to see this area return to organic growth in 2010.

CRETACEOUS/NIKANASSIN

GROSS ACREAGE POSITION	201,000
NET ACREAGE POSITION	116,000

Forest will ramp-up drilling activity in 2010 in its Canadian Deep Basin properties with a focus on stacked sand opportunities that exist in its Foothills and Wild River properties and on horizontal drilling in the Company's shallow oil resource play at Evi. Completion techniques include vertical commingled completions, with multi-layer fracture stimulations from the gas-bearing Nikanassin to the Cadotte formations, as well as horizontal multi-fractured wells targeting the oil-bearing Slave Point carbonates.



Based on highly successful completion techniques utilized in other development areas within Forest's portfolio, the Company employed enhanced drilling and completion techniques to its Foothills properties with a high degree of success. One well achieved an average 24-hour initial production rate of 32 MMcfe/d.

Based on the success in the Foothills and Wild River, Forest undertook a significant land acquisition campaign, which increased the net acreage position in the Deep Basin from 67,000 net acres at December 31, 2008 to 105,000 net acres at the end of February 2010, a 57% increase. In the Wild River field within the Deep Basin, Forest received regulatory approval that allows downspacing to six wells per section over a majority of the acreage. This enables Forest the ability to significantly ramp-up production in the field.

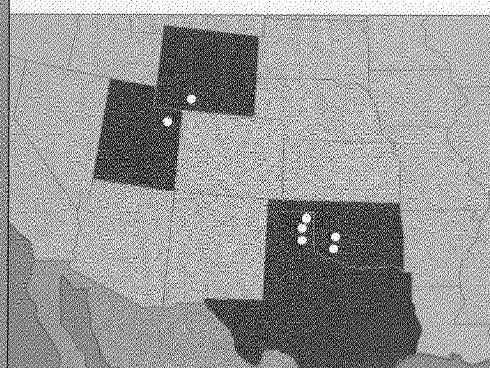
In Forest's Evi shallow oil resource play, horizontal drilling techniques with multi-stage hydraulic fracture completions have yielded highly-economic development wells. This has resulted in 24-hour initial production rates as high as 200 Bbls/d for approximately $2.0 million in drilling and completion costs. Based on the successful production results, Forest increased the net acreage position in the area from 22,000 net acres at December 31, 2008 to 32,000 net acres at the end of February 2010, a 45% increase.

With the success in the Deep Basin in 2009, Canadian Forest Oil is "back on the bit" and intends to run up to seven rigs during 2010, drilling 35–40 operated wells while capitalizing on the favorable Canadian royalty incentives that are currently in place.

Operational Fact Sheet

Western

	2009	2008	2007
NET PRODUCTION			
Gas (MMcf/d)	80.2	91.3	77.4
Liquids (MBbls/d)	10.2	11.3	10.7
ESTIMATED PROVED RESERVES			
Gas (Bcf)	362.9	575.0	408.7
Liquids (MMBbls)	27.8	68.9	59.9
Equivalent (Bcfe)	529.9	988.2	767.9
DEVELOPED ACREAGE			
Gross	258,123	384,511	353,754
Net	119,580	230,680	217,814
UNDEVELOPED ACREAGE			
Gross	211,305	416,240	1,128,547
Net	121,513	272,101	789,494
GROSS WELL COUNT			
Gas	928	943	3,663
Oil	66	1,945	2,251
CAPITAL EXPENDITURES In thousands			
	$157,875	$375,581	$278,701



2009 HIGHLIGHTS

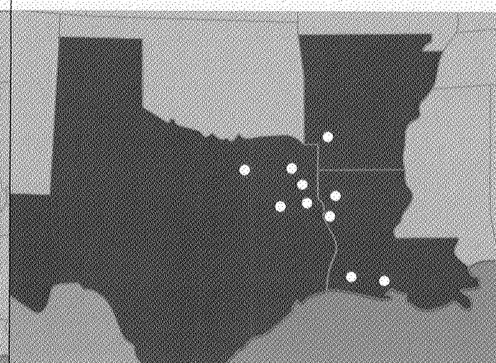
- Increased estimated proved reserves 19%, pro forma for divestitures, to 530 Bcfe at an organic reserve replacement ratio, excluding price revisions, of 396%
- Drilled 52 gross wells with a 100% success rate
- 100% horizontal drilling success rate in the Texas Panhandle Granite Wash Play with 24-hour initial production rates as high as 37 MMcfe/d
- 100% horizontal drilling success rate in the Texas Panhandle Lower Morrow Play with 24-hour initial production rates as high as 20 MMcfe/d
- Divested 541 Bcfe of estimated proved reserves and 55 MMcfe/d of production for approximately $908 million

2010 STRATEGY

- Drilling program calls for approximately 30–40 wells and a continued high pace of additional projects
- Plan to drill approximately 20–25 horizontal wells in the Texas Panhandle
- Focus horizontal Granite Wash efforts in Wheeler County and look to expand the Granite Wash play north into Hemphill County
- Expand horizontal drilling efforts in other zones in northwest Hemphill, Lipscomb and Roberts Counties
- Continue to leverage on the Lantern Drilling rigs as a tool to keep costs in check

Eastern

	2009	2008	2007
NET PRODUCTION			
Gas (MMcf/d)	123.4	103.4	66.0
Liquids (MBbls/d)	4.8	5.4	4.1
ESTIMATED PROVED RESERVES			
Gas (Bcf)	739.8	727.5	470.7
Liquids (MMBbls)	21.0	24.8	21.6
Equivalent (Bcfe)	866.0	876.1	600.3
DEVELOPED ACREAGE			
Gross	237,903	271,061	172,633
Net	171,520	187,641	113,557
UNDEVELOPED ACREAGE			
Gross	142,729	205,949	282,298
Net	78,578	120,132	139,101
GROSS WELL COUNT			
Gas	1,507	1,421	898
Oil	240	398	350
CAPITAL EXPENDITURES In thousands			
	$212,883	$489,384	$375,581



2009 HIGHLIGHTS

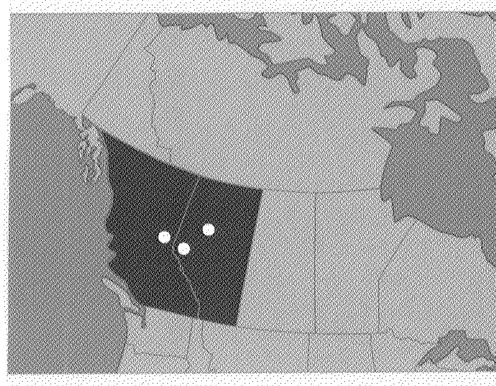
- Increased estimated proved reserves 2%, pro forma for divestitures, to 866 Bcfe at an organic reserve replacement ratio, excluding price revisions, of 427%
- Drilled 42 gross wells with a 95% success rate
- 100% horizontal drilling success rate in East Texas/North Louisiana with 24-hour initial production rates as high as 21 MMcfe/d
- Divested 10 Bcfe of estimated proved reserves and 2 MMcfe/d of production for approximately $25 million

2010 STRATEGY

- Drilling program calls for approximately 45–50 wells and a continued high pace of additional projects
- Plan to drill approximately 18–24 horizontal wells in East Texas/North Louisiana
- Focus horizontal Haynesville/Bossier Shale efforts in Red River and Sabine Parishes and look to expand the Haynesville/Bossier Shale program in East Texas
- Continue to leverage on the Lantern Drilling rigs as a tool to keep costs in check

Canada

	2009	2008	2007
NET PRODUCTION			
Gas (MMcf/d)	63.7	63.7	68.7
Liquids (MBbls/d)	2.3	3.0	2.9
ESTIMATED PROVED RESERVES			
Gas (Bcf)	221.2	237.5	208.2
Liquids (MMBbls)	16.9	8.8	7.3
Equivalent (Bcfe)	322.3	290.5	252.1
DEVELOPED ACREAGE			
Gross	251,120	297,238	286,016
Net	148,246	161,687	157,737
UNDEVELOPED ACREAGE			
Gross	812,021	822,662	852,704
Net	606,951	344,504	375,398
GROSS WELL COUNT			
Gas	565	668	626
Oil	364	356	341
CAPITAL EXPENDITURES In thousands			
	$85,709	$200,884	$173,212



2009 HIGHLIGHTS

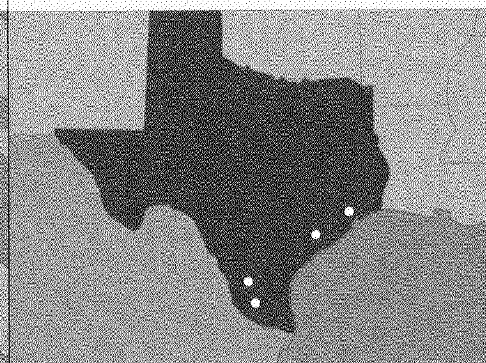
- Increased estimated proved reserves 51%, pro forma for divestitures, to 322 Bcfe at an organic reserve replacement ratio, excluding price revisions, of 436%
- Drilled 11 gross wells with a 100% success rate
- 100% success rate in the Deep Basin with 24-hour initial production rates as high as 32 MMcfe/d
- Received downspacing approval for four wells per section at Narraway
- Made significant investments to improve infrastructure to ensure takeaway capacity for future production
- Divested 77 Bcfe of estimated proved reserves and 11 MMcfe/d of production for approximately $121 million

2010 STRATEGY

- Drilling program calls for approximately 45–50 wells and a continued high pace of additional projects
- Plan to drill approximately 35–40 wells in the Deep Basin
- Focus development efforts in the Deep Basin to exploit multi-zone gas resource plays including the Nikanassin
- Expand drilling campaign at Evi through the application of horizontal drilling techniques with multi-stage fracture completions
- Plan to shoot seismic and drill a horizontal well in the Utica Shale play
- Continue monitization of existing non-core assets

Southern

	2009	2008	2007
NET PRODUCTION			
Gas (MMcf/d)	114.3	128.0	80.3
Liquids (MBbls/d)	2.6	2.2	1.6
ESTIMATED PROVED RESERVES			
Gas (Bcf)	312.8	417.1	408.5
Liquids (MMBbls)	6.3	6.7	5.7
Equivalent (Bcfe)	350.6	457.0	442.6
DEVELOPED ACREAGE			
Gross	207,309	175,091	192,752
Net	135,092	127,572	135,852
UNDEVELOPED ACREAGE			
Gross	109,848	54,943	73,843
Net	100,805	40,090	34,208
GROSS WELL COUNT			
Gas	1,300	1,268	1,429
Oil	65	36	23
CAPITAL EXPENDITURES In thousands			
	$103,638	$281,836	$103,614



2009 HIGHLIGHTS

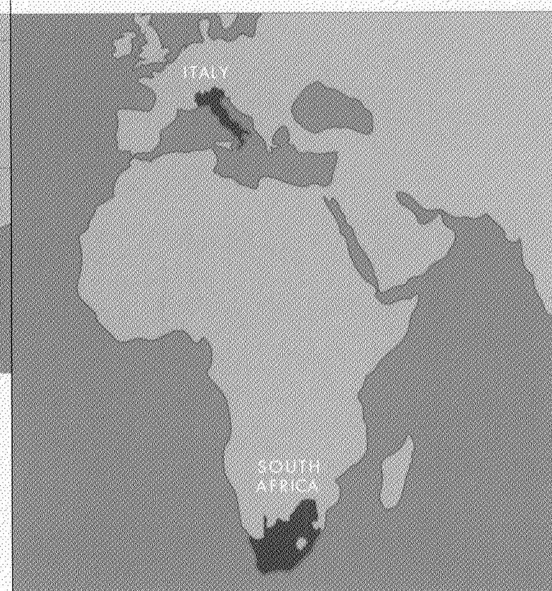
- Estimated proved reserves of 351 Bcfe
- Drilling success in the Wilcox with 24-hour initial production rates as high as 10 MMcfe/d
- Drilling success in the Vicksburg with 24-hour initial production rates as high as 11 MMcfe/d with 40% liquids
- Generated free cash flow of $66 million

2010 STRATEGY

- Drilling program calls for approximately 20–25 wells and a continued high pace of additional projects
- Plan to drill approximately 15–20 wells in the South Texas area
- Continue efforts in South Texas Vicksburg play with high liquids yield
- Continue horizontal development based on success achieved in 2009
- Expand horizontal drilling techniques to the Wilcox and Yegua trends

International

	2009	2008	2007
NET PRODUCTION			
Gas (MMcf/d)	–	–	–
Liquids (MBbls/d)	–	–	–
ESTIMATED PROVED RESERVES			
Gas (Bcf)	51.7	56.3	56.3
Liquids (MMBbls)	–	–	–
Equivalent (Bcfe)	51.7	56.3	56.3
DEVELOPED ACREAGE			
Gross	2,500	2,500	2,500
Net	2,250	2,250	2,250
UNDEVELOPED ACREAGE			
Gross	3,060,238	3,060,238	5,469,514
Net	1,705,999	1,762,453	2,967,091
GROSS WELL COUNT			
Gas	2	2	2
Oil	–	–	–
CAPITAL EXPENDITURES In thousands			
	$9,232	$6,949	$15,853



2009 HIGHLIGHTS

- Received production license in South Africa
- Submitted formal production license application in Italy to commence production from Forest's Monte Pallano property that tested at a combined initial rate of 22 MMcfe/d without fracture stimulation

2010 STRATEGY

- Continue progress towards achieving production licenses in Forest's concessions in Italy
- Continue progress in securing gas contracts in South Africa

Executive Officers

H. CRAIG CLARK, 53
President and
Chief Executive Officer
Years of Service: 9

MICHAEL N. KENNEDY, 35
Executive Vice President
and Chief Financial Officer
Years of Service: 9

JOHN C. RIDENS, 54
Executive Vice President
and Chief Operating Officer
Years of Service: 6

CECIL N. COLWELL, 59
Senior Vice President,
Worldwide Drilling
Years of Service: 21

LEONARD C. GURULE, 53
Senior Vice President,
Western Region
Years of Service: 7

CYRUS D. MARTER IV, 46
Senior Vice President,
General Counsel and Secretary
Years of Service: 8

GLEN J. MIZENKO, 47
Senior Vice President, Business
Development and Engineering
Years of Service: 9

VICTOR A. WIND, 36
Senior Vice President,
Chief Accounting Officer and
Corporate Controller
Years of Service: 5

MARK E. BUSH, 50
Vice President, Eastern Region
Years of Service: 13

RONALD C. NUTT, 52
Vice President, Southern Region
Years of Service: 3

Board of Directors

LOREN K. CARROLL, age 66, has been a director since 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, 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 October 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. Mr. Carroll graduated from California State University at Long Beach with a bachelor of science degree in accounting.

H. CRAIG CLARK, age 53, has served as our President and Chief Executive Officer, and as a director of Forest since July 2003. Mr. Clark joined Forest in September 2001 and served as President and Chief Operating Officer through July 2003. Mr. Clark was employed by Apache Corporation, an oil and gas exploration and production company, from 1989 to 2001, where he served in various management positions including Executive Vice President - U.S. Operations and Chairman and Chief Executive Officer of Pro Energy, an affiliate of Apache. Mr. Clark is a member of our Executive Committee. Mr. Clark graduated from Texas A&M University with a bachelor of science degree in engineering.

DOD A. FRASER, age 59, 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 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, Terra Industries, Inc., a nitrogen-based fertilizer company, and Acergy S.A., a sub-sea engineering and contracting company. Mr. Fraser serves as Chairman of our Audit Committee and is a member of our Nominating and Corporate Governance Committee. Mr. Fraser graduated from Princeton University with a bachelor of arts degree.

JAMES H. LEE, age 61, has been a director since 2003. 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 has been a director of Frontier Oil Corporation, a crude oil refining and wholesale marketing company, since 2000. He is a member of our Audit Committee and our Executive Committee. Mr. Lee graduated from Stanford University with a bachelor of arts degree in economics and from The Harvard Graduate School of Business Administration with an MBA.

JAMES. D. LIGHTNER, age 57, has been a director since 2004 and has served as our non-executive Chairman of the Board since May 2008. Mr. Lighter is Chief Executive Officer of Beacon E&P Company, an oil and gas exploration company, since its inception in 2009. Mr. Lightner was a Partner and Chief Executive Officer of Orion Energy Partners, an oil and gas exploration and production company, from its inception in August 2004 until its winding down in 2009. 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, until its sale to EnCana Oil & Gas (USA) Inc. in 2004. Prior to 1999, he served as Vice President and General Manager of EOG Resources, Inc., a publicly traded oil and gas exploration and production company. Mr. Lightner had been a director since November 2004 of W-H Energy Services Inc., an oil field services company, until its sale in July 2008. Mr. Lightner serves as Chairman of our Executive Committee and as a member of our Nominating and Corporate Governance Committee. Mr. Lightner received a bachelor of science degree in geology from Southern Illinois University, and a master of science degree in geology from the Australian National University.

PATRICK R. MCDONALD, age 52, has been a director since 2004. Mr. McDonald has served as Chief Executive Officer, President and Director of Nytis Exploration Company, an oil and gas exploration company, since April 2003. From 1998 to 2003, Mr. McDonald served as President, Chief Executive Officer, and Director of Carbon Energy Corporation, an oil and gas exploration and production company. From 1987 to 1997 Mr. McDonald served as Chief Executive Officer, President and Director of Interenergy Corporation, a natural gas gathering, processing, and marketing company. Prior to that he worked as an exploration geologist with Texaco International Exploration Company where he was responsible for oil and gas exploration efforts in the Middle East and Far East. Mr. McDonald serves on the board of directors for Basic Materials and Services, Leprechaun Resources, Ltd, MAK-J Energy Partners Ltd., Ohio Basic Minerals, Polaris Resources, Ltd, and Q Advisors LLC, all of which are private companies. Mr. McDonald is a member of our Audit Committee and serves as Chairman of the Compensation Committee. He is a Certified Petroleum Geologist and is a member of the American Association of Petroleum Geologists. Mr. McDonald received a bachelor of science degree in geology and economics from Ohio Wesleyan University and an MBA in finance from New York University.

RAYMOND I. WILCOX, age 64, has been a director since 2009. Mr. Wilcox served as President and Chief Executive Officer of Chevron Phillips Chemical Company LLC, producers of olefins and polyolefins, aromatics, alpha olefins, styrenics and specialty chemicals, from April 2006 until his retirement in March 2008. From 2002 until 2006, Mr. Wilcox served as Vice President of Chevron Corporation, a worldwide integrated energy company, and President of Chevron North America Exploration and Production Company, an oil and gas exploration and production company. Mr. Wilcox joined Chevron in 1968 and his career covered responsibilities in the upstream, midstream and chemical segments, and included activities in North America, Indonesia, Australia, Kazakhstan, the Far East, the Middle East and Africa. Mr. Wilcox previously served as a director of Dynegy, Inc. from June 2003 until March 2006. Mr. Wilcox is a member of our Nominating and Corporate Governance Committee and our Compensation Committee. He graduated from the University of Michigan with a bachelor of science degree in mechanical engineering.

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, 2009

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of 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 the 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 in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2009, the last business day of the registrant's most recently completed second fiscal quarter, was $1,660,195,622 (based on the closing price of such stock).

There were 112,428,756 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 19, 2010.

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, 2009 are incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1. Business.

General

Forest Oil Corporation ("Forest") is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969. Forest's total estimated proved reserves as of December 31, 2009 were approximately 2,121 Bcfe. At December 31, 2009, approximately 83% of Forest's estimated proved oil and gas reserves were in the United States, approximately 15% were in Canada, and approximately 2% were in Italy.

Throughout this Annual Report on Form 10-K we use the terms "Forest," "Company," "we," "our," and "us" to refer to Forest Oil Corporation and its subsidiaries. In the following discussion, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 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 "Glossary of Oil and Gas Terms," below, for the definition of certain terms.

Strategy

Over the last six years, we have pursued a strategy directed at transforming Forest from a predominantly offshore Gulf of Mexico oil and gas producer to a North American onshore company with a focus on unconventional resource plays having numerous lower risk opportunities for production and reserve growth. An integral part of this strategy has been the acquisition of properties in several core operational areas of focus while divesting our non-core assets outside of those areas. We also seek to maintain financial flexibility as part of our business strategy, which includes maintaining capital discipline and focusing on cost control.

Core Operational Areas

Forest's core operational areas, where the majority of its exploration and development activities are planned in 2010, are detailed below. Our 2010 budget provides for a significant increase in the level of drilling activity in these core areas compared to 2009. In addition to the core operational areas below, Forest owns and operates producing oil and gas properties throughout North America.

The Greater Buffalo Wallow Area

The Greater Buffalo Wallow area extends over a large area in the Texas Panhandle and Western Oklahoma. Forest holds approximately 94,000 net acres in the area primarily located in Hemphill, Lipscomb, Roberts, and Wheeler Counties in the Texas Panhandle. The area provides for excellent horizontal and vertical drilling opportunities targeting liquids-rich Granite Wash intervals as well as other multi-pay objectives such as the Atoka and Morrow formations. We drilled our first horizontal wells in the area in 2009, leveraging our database of over 400 wells in the area to determine attractive formations throughout our acreage position to initiate a horizontal drilling campaign. Based on the results of the first four operated horizontal wells drilled in the area, which had initial 24-hour production rates of approximately 30 MMcfe per day, we plan to significantly increase the number of horizontal wells drilled in 2010 by employing up to a four rig program, investing approximately $150 million for, among other projects, the drilling of 20 to 25 gross horizontal wells.

East Texas / North Louisiana Area

The East Texas / North Louisiana area includes our interests in approximately 154,000 net acres that are prospective for the Cotton Valley, Haynesville, Bossier and other formations. Since our entry into East Texas in 2006, we primarily targeted tight-gas sands in the Cotton Valley formation. In 2009, we expanded our drilling program in the region and drilled seven wells targeting the Haynesville formations, including four horizontal wells in Louisiana. These four wells had average initial 24-hour production rates of 18 MMcfe per day. In 2010, we plan to operate up to four rigs in the area and invest approximately $160 million for, among other projects, the drilling of 12 to 16 gross horizontal wells targeting the Haynesville Shale in North Louisiana and six to eight gross horizontal wells targeting the Cotton Valley Sands or Haynesville/Bossier formations in East Texas and North Louisiana

Canadian Deep Basin Area

The Canadian Deep Basin area is located in Alberta and British Columbia and primarily includes our interests in the Wild River, Narraway, Ojay, and Evi fields. As we did with our Greater Buffalo Wallow area development strategy, we plan to further delineate the Narraway, Ojay, and Wild River fields through the drilling of vertical wells to evaluate multiple objectives in these fields to potentially employ a horizontal drilling program in the future. Forest holds approximately 88,000 net acres in the basin and we plan to run up to a seven rig program during 2010. We intend to invest approximately $170 million in 2010 for, among other projects, the drilling of between 35 to 40 operated wells including horizontal wells in our oil-rich Evi field as well as vertical wells where multi-pay zones are being targeted in our Narraway, Ojay, and Wild River fields. The capital budget for the Deep Basin in 2010 was increased compared to prior years to take advantage of the current favorable royalty regime in place in Alberta.

Acquisition and Divestiture Activities

We pursue acquisitions that meet our criteria for investment returns and are consistent with our North American onshore low-risk development focus, and we pursue divestitures of non-core assets to upgrade our portfolio and further increase our operational efficiencies. Acquisitions in and around our existing core areas enable us to leverage our cost control abilities, technical expertise, and existing land and infrastructure positions. In general, our acquisition program has focused on acquisitions of properties that have substantial development drilling opportunities and undeveloped acreage. The following sets forth our significant acquisitions and divestures over the last several years.

Acquisitions

In September 2008, we acquired producing oil and natural gas properties located in our Greater Buffalo Wallow and East Texas / North Louisiana core areas from Cordillera Texas, L.P. for approximately $570 million in cash and 7.25 million shares of our common stock, valued at approximately $360 million based on a September 30, 2008 closing date. As of the closing date of the acquisition, the assets included approximately 350 Bcfe of estimated proved reserves and 85,000 net acres.

In May 2008, we acquired producing oil and natural gas properties located primarily in our East Texas / North Louisiana core area for approximately $284 million. As of the closing date of the acquisition, the assets included approximately 110 Bcfe of estimated proved reserves and 47,000 net acres.

In June 2007, we acquired 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. At the time of the acquisition, we estimated the Houston Exploration proved reserves to be 653 Bcfe. Pursuant to the terms and conditions of the agreement and plan of merger, Forest paid total merger consideration of $750 million in cash and issued approximately 24 million shares of our common stock, valued at $30.28 per share.

In March 2006, we acquired oil and natural gas properties located in our East Texas / North Louisiana core area for approximately $255 million in cash. As of the closing date of the acquisition, the assets included approximately 110 Bcfe of estimated proved reserves and approximately 26,000 net acres.

In April 2005, we acquired oil and natural gas properties in the Greater Buffalo Wallow core area for approximately $197 million in cash and the assumption of $35 million in debt. As of the closing date of the acquisition, the assets included approximately 120 Bcfe of estimated proved reserves and approximately 28,000 net acres.

Divestitures

During 2009, we sold all of our oil and gas properties located in Permian Basin in West Texas and New Mexico as well as other non-core oil and gas properties in the U.S. and Canada for approximately $1.1 billion in cash. We estimated the proved reserves associated with these properties were 628 Bcfe at the closings of the relevant transactions.

In November 2008, we sold the majority of our oil and gas properties located in the Rocky Mountains for approximately $198 million in cash. We estimated the proved reserves associated with these properties were 75 Bcfe at closing.

In August 2007, we sold all of our assets located in Alaska to Pacific Energy Resources Ltd. ("PERL") which were estimated to have proved reserves of 173 Bcfe at the time of closing. Total consideration received for the assets included $400 million in cash as well as 10 million shares of PERL common stock and a zero coupon senior subordinated note from PERL due 2014.

In March 2006, we completed the spin-off of our 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 a Forest subsidiary that held our offshore Gulf of Mexico assets to holders of record of Forest common stock as of the close of business on February 21, 2006. Immediately following the Spin-off, the Forest subsidiary was merged with a subsidiary of Mariner Energy, Inc. ("Mariner"), at which time the 50.6 million shares included in the Spin-off were exchanged for an equal number of Mariner common shares. Mariner's common stock commenced trading on the New York Stock Exchange ("NYSE") on March 3, 2006. We estimated the proved reserves associated with the Spin-off to be 313 Bcfe at the time of closing.

Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2009, based on the Henry Hub price of $3.87 per MMBtu for natural gas and the West Texas Intermediate price of $61.08 per barrel for oil, each of which represents the unweighted arithmetic average of the first-day-of-the-month prices during the twelve-month period prior to December 31,

2009. See—"*Preparation of Reserves Estimates*" below and Note 17 to the Consolidated Financial Statements for additional information regarding our estimated proved reserves.

	Estimated Proved Reserves		
	Natural Gas (MMcf)	**Oil and Natural Gas Liquids (MBbls)**	**Total (MMcfe)**
Developed:			
United States	916,005	34,364	1,122,189
Canada	169,740	6,202	206,952
Total developed	1,085,745	40,566	1,329,141
Undeveloped:			
United States	499,426	20,804	624,250
Canada	51,461	10,652	115,373
Italy	51,738	—	51,738
Total undeveloped	602,625	31,456	791,361
Total estimated proved reserves	1,688,370	72,022	2,120,502

As of December 31, 2009, Forest had estimated proved reserves of 2,121 Bcfe. Of that total, 1,746 Bcfe (83%) were in the United States, 322 Bcfe (15%) were in Canada, and 52 Bcfe (2%) were in Italy. During 2009, we added 663 Bcfe of estimated proved reserves through extensions and discoveries which were offset by property sales of 628 Bcfe, negative performance revisions of 88 Bcfe, and negative product price revisions of 312 Bcfe, which were primarily related to a decrease in the natural gas price required to be assumed to calculate reserves volumes.

As of December 31, 2009, proved undeveloped reserves ("PUDs") were estimated to be 791 Bcfe, or 37% of estimated proved reserves, compared to 989 Bcfe, or 37% of estimated proved reserves as of December 31, 2008. The net reduction of 198 Bcfe was primarily due to negative price-related revisions and asset sales offset by extensions and discoveries. See "Strategy—*Acquisition and Divestiture Activities—Divestitures*" above for a discussion of the divestitures completed during 2009. We invested $74 million to convert 32 Bcfe of our December 31, 2008 PUD reserves to proved developed reserves during 2009. During the years 2006 to 2008, we converted, on average, 120 Bcfe per year from PUD reserves to proved developed reserves. We intend to convert the PUDs recorded as of December 31, 2009 to proved developed reserves within five years.

The estimated proved reserves presented in the table above were calculated in accordance with the Securities and Exchange Commission's ("SEC") "Modernization of Oil and Gas Reporting" rules, which were first effective for December 31, 2009 reporting. These rules include calculating estimated proved reserves based on the average prices during the twelve-month period prior to December 31, 2009, with such prices determined as the unweighted arithmetic average of the first-day-of-the-month prices for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Prior to the new rules, estimated proved reserves were calculated using year-end spot prices, including the consideration of changes in existing prices provided only by contractual arrangements and excluding escalations based upon future conditions. In the table below, Forest presents estimated quantities of proved reserves as of December 31, 2009 using the year-end Henry Hub spot price of $5.79 per MMBtu for natural gas and the year-end West Texas Intermediate spot price of $79.36 per barrel for oil.

	Estimated Proved Reserves—Alternative Pricing[1]		
	Natural Gas (Bcf)	Oil and Natural Gas Liquids (MMBbls)	Total (Bcfe)
Total estimated proved reserves	2,018	81	2,503

(1) Pricing based on the December 31, 2009 spot prices for natural gas and oil.

The following table sets forth the pre-tax PV-10 (present value of future net revenues before income taxes discounted at 10%) and the standardized measure of discounted future net cash flows of our reserves using the unweighted arithmetic average first-day-of-the-month prices during the twelve-month period prior to December 31, 2009 as well as the alternative pricing of $5.79 per MMBtu for natural gas and $79.36 per barrel for oil. Forest presents the pre-tax PV-10 value, which is not a financial measure accepted under Generally Accepted Accounting Principals ("GAAP"), because it is a widely used industry standard which we believe is useful to those who may review this Annual Report on Form 10-K when comparing our asset base and performance to other comparable oil and gas exploration and production companies. The table also reconciles the pre-tax PV-10 value to the standardized measure of discounted future net cash flows by reducing the pre-tax PV-10 values by the estimated income tax effects discounted at 10% per annum.

	Twelve Month Average Price	Alternative Price
Henry Hub natural gas price	$ 3.87	5.79
West Texas Intermediate oil price	61.08	79.36
Pre-tax PV-10 value (in thousands)	$2,337,342	4,495,542
Less: Income tax effects discounted at 10% per annum (in thousands)	284,343	1,124,490
Standardized measure of discounted future net cash flows (in thousands)	$2,052,999	3,371,052

Preparation of Reserves Estimates

Our reserve estimates as of December 31, 2009 presented herein were made in accordance with the SEC's "Modernization of Oil and Gas Reporting" rules, which were effective for annual reports for fiscal years ending on or after December 31, 2009. The new SEC rules include updated definitions of proved oil and gas reserves, proved undeveloped oil and gas reserves, oil and gas producing activities and other terms used in estimating proved oil and gas reserves. Proved oil and gas reserves as of December 31, 2009 were calculated based on the prices for oil and gas during the twelve month period before the reporting date, determined as unweighted arithmetic averages of the first-day-of-the-month prices for each month within such period, rather than the year-end spot prices, which had been used in years prior to 2009. Undrilled locations can be classified as having proved undeveloped reserves if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. The new SEC rules broadened the types of technologies that a company may use to establish reserve estimates and also broadened the definition of oil and gas producing activities to include the extraction of non-traditional resources, including bitumen extracted from oil sands as well as oil and gas extracted from shales.

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 changes 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 Part I, Item 1A—"Risk Factors," for a description of some of the risks and uncertainties associated with our business and reserves.

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

Forest's Senior Vice President, Business Development and Engineering, Glen Mizenko, has twenty-five years of experience in oil and gas exploration and production and has held this position since May 2007. Prior to that time, Mr. Mizenko held positions of increasing responsibility at Forest since joining the Company in early 2001. Prior to joining the Company, Mr. Mizenko held various positions in reservoir engineering, development planning, and operations management with Shell Oil Company, Benton Oil and Gas Company, and British Borneo Oil and Gas PLC. Mr. Mizenko received a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1985 and a Masters of Business Administration from the University of Houston in 1993. He is a twenty-five year member of the Society of Petroleum Engineers.

Independent Audit of Reserves

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

For the years ended December 31, 2009, 2008, and 2007, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the year ended December 31, 2009, DeGolyer and MacNaughton independently audited estimates relating to properties constituting approximately 85% of our reserves by NPV as of December 31, 2009. When compared on a field-by-field basis, some of Forest's estimates of proved reserves were greater and some were lesser than the estimates prepared by DeGolyer and MacNaughton. However, in the aggregate, Forest's estimates of total proved reserves were within five percent of DeGolyer and MacNaughton's aggregate estimate of proved reserves for the fields audited. The lead technical person at DeGolyer and MacNaughton primarily responsible for overseeing the audit of our reserves is a Registered Professional Engineer in the State of Texas, is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists, and has in excess of 35 years of experience in oil and gas reservoir studies and reserves evaluations.

Drilling Activities

During 2009, we drilled a total of 117 gross wells, of which 28 were classified as exploratory and 89 were classified as development. Our 2009 drilling program achieved a 94% success rate. The following table summarizes the number of wells drilled during 2009, 2008, and 2007, 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, 2009, we had 21 gross (11 net) wells in progress in the United States and 10 gross (6 net) wells in progress in Canada.

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
United States						
Productive	76	47	550	323	374	207
Non-productive[1]	6	4	15	11	16	13
Total	82	51	565	334	390	220
Canada						
Productive	7	3	64	39	52	32
Non-productive[1]	—	—	—	—	1	1
Total	7	3	64	39	53	33
Total development wells	89	54	629	373	443	253
Exploratory wells, completed as:						
United States						
Productive	23	14	72	54	38	25
Non-productive[1]	—	—	3	2	5	3
Total	23	14	75	56	43	28
Canada						
Productive	4	2	10	8	7	3
Non-productive[1]	—	—	—	—	—	—
Total	4	2	10	8	7	3
Italy						
Productive	—	—	—	—	2	2
Non-productive[1]	1	1	—	—	—	—
Total	1	1	—	—	2	2
Total exploratory wells	28	17	85	64	52	33

(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).

Oil and Gas Wells and Acreage

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, 2009, Forest owned interests in 545 gross wells containing multiple completions. The following table summarizes our productive wells as of December 31, 2009, all of which are located in the United States, Canada, and Italy.

	United States		Canada		Italy		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gas	3,735	2,801	565	357	2	2	4,302	3,160
Oil	371	234	364	258	—	—	735	492
Total	4,106	3,035	929	615	2	2	5,037	3,652

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, 2009. 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. At December 31, 2009, approximately 8%, 13%, and 10% of our net undeveloped acreage in the United States and Canada was held under leases that will expire in 2010, 2011, and 2012, respectively, if not extended by exploration or production activities.

	Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net
United States:				
Western[(1)]	258,123	119,580	211,305	121,513
Eastern[(2)]	237,903	171,520	142,729	78,578
Southern[(3)]	207,309	135,092	109,848	100,805
	703,335	426,192	463,882	300,896
Canada[(4)]	251,120	148,246	812,021	606,951
International:				
South Africa[(5)]	—	—	2,771,695	1,474,542
Italy	2,500	2,250	288,543	231,457
	2,500	2,250	3,060,238	1,705,999
Total	956,955	576,688	4,336,141	2,613,846

(1) The Western Business Unit's acreage is primarily located in the Greater Buffalo Wallow area in the Texas Panhandle and Western Oklahoma as well as in the Uintah field in Utah.

(2) The Eastern Business Unit's acreage is primarily located in the East Texas / North Louisiana area as well as in the Arkoma Basin in Arkansas.

(3) The Southern Business Unit's acreage is primarily located in South Texas.

(4) The Canadian Business Unit's acreage is primarily located in the Deep Basin area in Alberta and British Columbia as well as in the St. Lawrence Lowlands in Quebec.

(5) Forest applied to the South African government to convert one existing prospecting sublease (known as Block 2C) into an Exploration Right, and for a Production Right covering the geographic area of our other prospecting sublease (known as Block 2A). The Block 2A Production Right was granted in August 2009. The first term of this Production Right is for up to five years during which we, and our partners, are permitted to develop the local market for natural gas. Required work programs are minimal and full development remains contingent at our and our partners' option. The Block 2C Exploration Right conversion is expected to be executed in 2010. It requires a work program of one exploration well during the initial three-year period, with additional work obligations expected in any further exploration periods.

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, 2009, 2008, and 2007 by geographical area. Forest does not have any fields that contain 15% or more of the Company's total estimated proved reserves.

	United States			Canada			Total Company		
	2009	2008	2007	2009	2008	2007	2009	2008	2007
Natural Gas:									
Average sales price (per Mcf)	$ 3.33	7.54	5.95	3.15	6.98	5.29	3.30	7.45	5.79
Production volumes (MMcf)	116,029	118,120	82,963	23,248	23,313	25,079	139,277	141,433	108,042
Liquids:									
Oil and condensate:									
Average sales price (per Bbl)	$ 56.87	96.85	67.91	51.14	86.68	58.05	55.98	95.07	66.44
Production volumes (MBbls)	3,397	3,778	4,504	626	802	793	4,023	4,580	5,297
Natural gas liquids:									
Average sales price (per Bbl)	$ 25.17	44.54	39.32	30.82	60.71	43.54	25.57	45.94	39.75
Production volumes (MBbls)	3,012	3,151	2,381	230	300	267	3,242	3,451	2,648
Total liquids:									
Average sales price (per Bbl)	$ 41.97	73.06	58.02	45.68	79.61	54.40	42.41	73.96	57.54
Production volumes (MBbls)	6,409	6,929	6,885	856	1,102	1,060	7,265	8,031	7,945
Average sales price (per Mcfe)	**$ 4.24**	**8.75**	**7.18**	**3.95**	**8.37**	**6.05**	**4.20**	**8.69**	**6.96**
Total production volumes (MMcfe)	**154,483**	**159,694**	**124,273**	**28,384**	**29,925**	**31,439**	**182,867**	**189,619**	**155,712**
Production costs (per Mcfe):									
Lease operating expenses	$ .77	.83	1.09	.97	1.21	1.00	.80	.89	1.08
Transportation and processing costs	.08	.06	.08	.28	.32	.33	.11	.10	.13
Production costs excluding production and property taxes (per Mcfe)	.86	.89	1.17	1.25	1.53	1.33	.92	.99	1.21
Production and property taxes	.26	.49	.42	.10	.12	.11	.23	.43	.35
Total production costs (per Mcfe)	**$ 1.12**	**1.38**	**1.59**	**1.35**	**1.65**	**1.44**	**1.15**	**1.42**	**1.56**

Marketing and Delivery Commitments

Our natural gas production is generally sold on a month-to-month basis in the spot market, priced in reference to published indices. Our oil production is generally sold under short-term contracts at prices based upon refinery postings and is typically sold at the wellhead. Our natural gas liquids production is typically sold under term agreements at prices based on postings at large fractionation facilities. We believe that the loss of one or more of our current oil, natural gas, or natural gas liquids purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption. We had no material delivery commitments as of February 25, 2010.

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, and acquire additional leases and prospects for future development and exploration. 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. See Part I, Item 1A—"Risk Factors—*Competition within our industry is intense and may adversely affect our operations*" below.

Regulation

Our oil and gas operations are subject to various U.S. federal, state, and local laws and regulations, Canadian federal, provincial, and local laws and regulations, and local and national laws and regulations in Italy and South Africa. These laws and regulations may be changed in response to economic or political conditions. Matters subject to current governmental regulation and/or pending legislative or regulatory changes include the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation 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, unitization and pooling of properties, taxation, and the use of derivative hedging instruments. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of our operations. At various times, regulatory agencies have imposed price controls and limitations on oil and 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, Italy, and South Africa 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.

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 plugging and 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 that 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, 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.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act ("NGA") to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as Forest, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission ("FERC"), in contravention of rules prescribed by the FERC. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC's enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In December 2007, the FERC issued rules requiring that any market participant, including a producer such as Forest, that engages in physical sales for resale or purchases for resale of natural gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report such sales or purchases to the FERC, beginning on May 1, 2009. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. On September 18, 2008 the FERC issued its order on rehearing, which largely approved the existing rules, except the FERC exempted from the reporting requirement certain types of purchases and sales, including purchases and sales of unprocessed gas and bundled sales of gas made pursuant to state regulated retail tariffs. Also, the FERC clarified that other end use purchases and sales are not exempt from the reporting requirements. The monitoring and reporting required by the new rules will likely increase our administrative costs. Forest does not anticipate it will be affected any differently than other producers of natural gas.

Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by Congress, the states, the FERC, and the courts. For instance, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations—an important process used in the completion of our oil and gas wells—to regulation under the act. If adopted, this legislation could establish an additional level of regulation, and impose additional costs, on our operations. We cannot predict when or whether any such proposal, or any additional new legislative or regulatory proposal, may become effective. No material portion of Forest's business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the federal government.

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 governing land tenure, royalties, production rates and taxes, environmental protection, and other matters under their respective jurisdictions. The royalty regime in the provinces where 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 of 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 the Province of Alberta. The Alberta Government implemented a new oil and gas royalty framework effective 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 uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil range from 0% to 50%. Natural gas royalty rates range from 5% to 50%. In comparison, under the prior royalty regime, royalty rates ranged from 10% to 35% for conventional oil and from 5% to 35% for natural gas.

In November 2008, the Alberta Government announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 meters and 3,500 meters (or 3,281 feet and 11,483 feet), which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. The election for transition royalty rates for wells brought on production after June 30, 2009, must be made before the end of the first month in which production begins. Re-entry wells that are given a new drill date are also eligible for the transition option. All wells using the transitional royalty rates must shift to the new royalty framework rates on January 1, 2014.

Our drilling programs in Alberta have included, and in the future may include, deeper wells. On January 1, 2009, two new royalty programs impacting deep drilling activities went into effect, including the Deep Oil Exploration Program ("DOEP") and the Natural Gas Deep Drilling Program ("NGDDP"). These programs provide upfront royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 meters (6,562 feet) with a Crown interest and must be spudded after January 1, 2009. Oil wells in this category qualify for a royalty exemption on either the first $1,000,000 of royalty or the first 12 months of production. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 meters (8,202 feet). The NGDDP will have an escalating royalty credit in line with progressively deeper wells from $625 per meter ($191 per foot) to a maximum of $3,750 per meter ($1,143 per foot) and there are additional benefits for the deepest wells. A minimum 5% royalty will apply to these gas wells. Both the DOEP and the NGDDP are five year programs. Any wells drilled after December 31, 2013, will not qualify under either program. No royalty adjustments will be granted under either the DOEP or the NGDDP after December 31, 2018. The majority of our drilling activities and wells in Alberta will be subject to the new royalty framework or, at our election, the transitional rules. As a result, wells that we drill in the future may be subject to the new higher royalty rates, which may be partially offset by credits for deep wells, while our existing production base will be subject to lower royalty rates.

On March 3, 2009, the Alberta Government announced a new incentive program, which includes a drilling royalty credit for new oil, natural gas and non-project oil sands wells spudded and having a finished drill date between April 1, 2009 and March 31, 2011. This program provides a royalty credit of up to $200 per meter drilled with certain annual limitations on the amount of annual credits received directly from the Government. In addition, the program provides for a maximum 5% royalty rate for the first twelve months of production from wells that begin producing between April 1, 2009, and March 31, 2010, to a maximum of 50 MBbls of oil or 500 MMcf of natural gas.

Environmental

As an operator of oil and natural gas properties in the United States and Canada, and with exploratory and development operations in Italy and South Africa, we are subject to stringent national, 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 or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

We currently operate or lease, and have in the past operated or leased, a number of properties that for many years have been used for the exploration and production of oil and 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 previously disposed wastes or remediate property contamination, or to perform well pluggings or pit closure or other actions of a remedial nature to prevent future contamination.

Canada and Italy are signatories to the United Nations Framework Convention on Climate Change and have ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"). The Canadian federal government previously released the *Regulatory Framework for Air Emissions*, updated March 10, 2008 by *Turning the Corner: Regulatory Framework for Industrial Greenhouse Emissions* (collectively, the "Regulatory Framework") for regulating GHG emissions and in doing so proposed mandatory emissions intensity reduction obligations on a sector by sector basis. Legislation to implement the Regulatory Framework had been expected to be put in place this year, but the federal government has delayed the release of any such regulation and potential federal requirements in respect of GHG emissions are unclear. On January 30, 2010, the Canadian federal government announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020, in order to align itself with U.S. policy. In 2009, the Canadian federal government announced its commitment to work with the provincial governments to implement a North America-wide cap and trade system for GHG emissions, in cooperation with the United States. Under the system, Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. It is uncertain whether either federal GHG regulations or an integrated North American cap-and-trade system will be implemented, or what obligations might be imposed under any such systems.

Additionally, GHG regulation can take place at the provincial and municipal level. For example, Alberta introduced the Climate Change and Emissions Management Act, which provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulation, the Specified Gas Emitters Regulation, effective July 1, 2007, requires mandatory emissions reductions through the use of emissions intensity targets, and a company can meet the applicable emissions limits by making emissions intensity improvements at facilities, offsetting GHG emissions by purchasing offset credits or emission performance credits in the open market, or acquiring "fund credits" by making payments of $15 per ton of GHG emissions to the Alberta Climate Change and Management Fund. The Alberta government recently announced its intention to raise the price of fund credits. The Specified Gas Reporting Regulation imposes GHG emissions reporting requirements if a company has GHG emissions of 100,000 tons or more from a facility in a year. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations in permits and under other environmental regulations. The Canadian federal government currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. The direct and indirect costs of these regulations may adversely affect our operations and financial results.

In 2009, the U.S. House of Representatives passed a bill to control and reduce the emission of GHGs in the United States through the grant of emission allowances which would gradually be decreased over time, and the Senate is considering similar legislation. Moreover, nearly half of the states, either individually or through multi-state initiatives, already have begun implementing legal measures to reduce emissions of GHGs. Also, the Supreme Court held in *Massachusetts et al v. EPA* (2007) that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act, which could result in future regulation of GHG emissions from stationary and non-stationary sources, even if Congress does not adopt new legislation specifically addressing emissions of GHGs. In December 2009, the United States Environmental Protection Agency ("EPA") published its findings that GHG emissions present an endangerment to public health and the environment because such emissions, according to the EPA, are contributing to warming of the earth's atmosphere and other climate changes. These findings allow the EPA to implement regulations that would restrict GHG emissions under existing provisions of the Clean Air Act. Accordingly, the EPA has proposed regulations that would require a reduction of GHG emissions from motor vehicles and could trigger permit review for GHG emissions from large stationary sources such as power plants or industrial facilities. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources beginning in 2011 for emissions occurring in 2010. While it is not possible at this time to fully predict how legislation or new regulations that may be adopted in the United States to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have an adverse effect on demand for the oil and natural gas that we produce.

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, 2009, we had 705 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 15 to the Consolidated Financial Statements of this Annual Report on 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 the substantial majority of our properties. In addition, our properties may also be subject to liens incident to operating agreements, as well as other customary encumbrances, easements, and restrictions, and for current taxes not yet due. Forest's general practice is to conduct a title examination on material property acquisitions. Prior to the commencement of drilling operations, a title examination and, if necessary, curative work is performed. The methods of title examination that we have adopted are reasonable in the opinion of management and are designed to 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 Annual Report on 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) 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 a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well or a service well.

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

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

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

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

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

Proved undeveloped reserves. 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 economic quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

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

Available Information

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

Also posted on Forest's website, and available in print upon written request of any shareholder addressed to the Secretary of Forest, at 707 17th Street, Suite 3600, Denver, Colorado 80202, are Forest's Corporate Governance Guidelines, the charters for 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.

Forward-Looking Statements

The information in this Annual Report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are statements other than statements of historical or present facts, that address activities, events, outcomes, and other matters that Forest plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates, or anticipates (and other similar expressions) will, should, or may occur in the future. Generally, the words "expects," "anticipates," "targets," "goals," "projects," "intends," "plans," "believes," "seeks," "estimates," "may," "will," "could," "should," "future," "potential," "continue," variations of such words, and similar expressions identify 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.

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

- estimates of our oil and natural gas reserves;
- estimates of our future oil and natural gas production, including estimates of any increases or decreases in our production;
- our future financial condition and results of operations;
- our future revenues, cash flows, and expenses;
- our access to capital and our anticipated liquidity;
- our future business strategy and other plans and objectives for future operations;
- our outlook on oil and gas prices;
- the amount, nature, and timing of future capital expenditures, including future development costs;
- our ability to access the capital markets to fund capital and other expenditures;
- our assessment of our counterparty risk and the ability of our counterparties to perform their future obligations; and
- the impact of federal, state, and local political, regulatory, and environmental developments in the United States and certain foreign locations where we conduct business operations.

We believe the expectations and forecasts reflected in our forward-looking statements are reasonable, but we can give no assurance that they will prove to be correct. We caution you that these forward-looking statements can be affected by inaccurate assumptions and 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. See "Competition" and "Regulation" above, as well as Part I, Item 1A—"Risk Factors," Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources," and Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk" for a description of various, but by no means all, factors that could materially affect our ability to achieve the anticipated results described in the forward-looking statements.

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

Item 1A. Risk Factors.

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

Oil and natural gas prices are volatile. Declines in commodity prices have adversely affected, and in the future may adversely affect, our financial condition and results of operations, cash flows, access to the capital markets, and ability to grow.

Our financial condition, operating results, and future rate of growth depend upon the prices that we receive for our oil and natural gas. Prices also affect our cash flow available for capital expenditures and our ability to access funds under our bank credit facilities and through the capital markets. The amount available for borrowing under our bank credit facilities is subject to a global borrowing base, which is determined by our lenders taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. Declines in oil and natural gas prices have in the past adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our global borrowing base. Future commodity price declines may have similar adverse effects on our reserves and global borrowing base. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—*Bank Credit Facilities*," for more details. Further, because we have elected to use the full-cost accounting method, each quarter we must perform a "ceiling test" that is impacted by declining prices. Significant price declines could cause us to take one or more ceiling test write-downs, which would be reflected as non-cash charges against current earnings. See "*—Lower oil and gas prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values.*"

In addition, significant or extended price declines may also adversely affect the amount of oil and natural gas that we can produce economically. A reduction in production could result in a shortfall in our expected cash flows and require us to reduce our capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively impact our ability to replace our production and our future rate of growth.

The markets for oil and natural gas have been volatile historically and are likely to remain volatile in the future. Oil spot prices reached historical highs in July 2008, and natural gas spot prices reached near historical highs in July 2008. Prices have declined significantly since that time and may continue to fluctuate widely in the future. The prices we receive for our oil and natural gas depend upon factors beyond our control, including among others:

- domestic and global supplies, consumer demand for oil and natural gas, and market expectations regarding supply and demand;
- domestic and worldwide economic conditions;
- the impact of the U.S. dollar exchange rate on oil and natural gas prices;

- the proximity, capacity, cost, and availability of oil and natural gas pipelines, processing, gathering, and other transportation facilities;
- weather conditions;
- political conditions, instability and armed conflicts in oil-producing and gas-producing regions;
- actions by the Organization of Petroleum Exporting Countries directed at maintaining prices and production levels;
- the price and availability of imports of oil and natural gas;
- the impact of energy conservation efforts and the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxes; and
- technological advances affecting energy consumption and supply.

These factors make it very difficult to predict future commodity price movements with any certainty. We sell the majority of our oil and natural gas production at current prices rather than through fixed-price contracts. However, we do enter into derivative instruments to reduce our exposure to fluctuations in oil and natural gas prices. See "—*Our use of hedging transactions could result in financial losses or reduce our income.*" Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Approximately 80% of our estimated proved reserves at December 31, 2009 were natural gas, and, as a result, our financial results will be more sensitive to fluctuations in natural gas prices.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities, and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy.

We require substantial capital expenditures to conduct our exploration, development, and production operations, engage in acquisition activities, and replace our production. Historically, we have funded our capital expenditures through a combination of our cash flows from operations, our bank credit facilities, and debt and equity issuances. We also engage in asset sale transactions to fund capital expenditures when market conditions permit us to complete transactions on terms we find acceptable. For any large acquisitions or other exceptional expenditures, we expect we would need to access the public or private capital markets or complete additional asset sales. If our revenues and cash flows decrease in the future as a result of a decline in commodity prices, however, and we are unable to obtain additional debt or equity financing in the private or public capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to replace our reserves or maintain our production levels.

Our future revenues, cash flows, and spending levels are subject to a number of factors, including commodity prices, the level of production from existing wells, and our success in developing and producing new wells. Further, our ability to access funds under our bank credit facilities is based on a global borrowing base, which is subject to periodic redeterminations based on our estimated proved reserves and prices that will be determined by our lenders using the prices prevailing at such time. If the prices for oil and natural gas decline, or if we have a downward revision in estimates of our proved reserves, the global borrowing base may be reduced. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—*Bank Credit Facilities*," for more details.

Our ability to access the private and public debt and equity markets and complete future asset monetization transactions is also dependent upon oil and natural gas prices, in addition to a number of other factors, some of which are outside our control. These factors include, among others:

- the value and performance of our debt and equity securities;
- the credit ratings assigned to our debt by independent rating agencies;
- domestic and global economic conditions; and
- conditions in the domestic and global financial markets.

The credit crisis and related turmoil in the global financial systems have had an impact on our business and our financial condition, and we may face additional challenges if economic and financial market conditions worsen.

The distressed economic conditions also may adversely affect the collectibility of our trade receivables. For example, our accounts receivable are primarily from purchasers of our oil and natural gas production and other exploration and production companies that own working interests in the properties that we operate This industry concentration could adversely impact our overall credit risk, because our customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices, and other conditions. Further, the credit crisis and turmoil in the financial markets could cause our commodity derivative instruments to be ineffective in the event a counterparty were unable to perform its obligations or seek bankruptcy protection.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

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

We have a substantial amount of indebtedness, and we may incur more debt in the future. This indebtedness may have several important effects on our business and operations; among other things, it may:

- require us to use a significant portion of our cash flow to pay principal and interest on the debt, which will reduce the amount available to fund working capital, capital expenditures, and other general corporate purposes;
- adversely affect the credit ratings assigned by third party rating agencies, which have in the past and may in the future downgrade their ratings of our debt and other obligations due to changes in 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;
- limit 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 credit and debt agreements contain various restrictive covenants. A failure on our part to comply with the financial and other restrictive covenants contained in our bank credit facilities and the indentures pertaining to our outstanding senior notes could result in a default under these agreements. Any default under our bank credit facilities or indentures could adversely affect our business and our financial condition and results of operations, and would impact our ability to obtain financing in the future. In addition, the global borrowing base included in our bank credit facilities is subject to periodic redetermination by our lenders. A lowering of our global borrowing base could require us to repay indebtedness in excess of the borrowing base. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—*Bank Credit Facilities*."

A higher level of debt will increase the risk that we may default on our financial obligations. Our ability to meet our debt obligations and other expenses will depend on our future performance. Our future performance will be affected by oil and natural gas prices, financial, business, domestic and global economic conditions, governmental regulations and environmental regulations, 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.

A portion of our borrowings from time to time may be at variable interest rates, making us vulnerable to increases in interest rates.

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 entered into 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 two years or less; however, in conjunction with acquisitions, we sometimes enter into or acquire hedges for longer periods. Our hedging transactions expose us to certain risks and financial losses, including, among others:

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

Our hedging transactions will impact our earnings in various ways. Due to the volatility of oil and natural gas prices, we may be required to recognize mark-to-market gains and losses on derivative instruments as the estimated fair value of our commodity derivative instruments is subject to significant fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period to period estimates and will be a function of the actual price of the commodities on the settlement date of the derivative instrument. We expect that commodity prices will continue to fluctuate in the future and, as a result, our periodic financial results will continue to be subject to fluctuations related to our derivative instruments.

Currently, all but two of our outstanding commodity derivative instruments are with certain lenders or affiliates of the lenders under our bank credit facilities. We generally do not enter into derivative instruments that require us to provide margin to counterparties. Our obligations under our existing derivative instruments with our lenders are secured by the security documents executed by the parties under our bank credit facilities. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—*Realized and Unrealized Gains and Losses on Derivative Instruments*" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" as well as Item 7A, "Quantitative and Qualitative Disclosure about Market Risk—Commodity Price Risk" for further details about our hedging activities.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in the Obama Administration's budget proposal for fiscal year 2011, released by the White House on February 1, 2010, is the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Lower oil and gas prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values.

We use the full cost method of accounting to report our oil and gas operations. Under this method, we capitalize the cost to acquire, explore for, and develop oil and gas properties. Under full cost accounting rules, the net capitalized costs of proved 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 proved oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling test write-down." Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write-down would not impact cash flow from operating activities, but it would reduce our shareholders' equity. See Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies, Estimates, Judgments, and Assumptions—*Full Cost Method of Accounting*" below, for further details.

Investments in unproved properties, including capitalized interest costs, are also assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. The amount of impairment assessed, if any, is added to the costs to be amortized, or is reported as a period expense, as appropriate. If an impairment of unproved properties results in a reclassification to proved oil and gas properties, the amount by which the ceiling limit exceeds the capitalized costs of proved oil and gas properties would be reduced.

We also assess the carrying amount of goodwill in the second quarter of each year and at other periods when events occur that may indicate an impairment exists. These events include, for example, a significant decline in oil and gas prices or a decline in our market capitalization.

The risk that we will be required to write-down the carrying value of our oil and gas properties, our unproved properties, or goodwill increases when oil and gas prices are low. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. For example, we recorded non-cash ceiling test write-downs of approximately $2.4 billion in 2008 and $1.6 billion in 2009. These write-downs were reflected as charges to net earnings. Additional write-downs of our full cost pools may be required if oil and natural gas prices decline further, unproved property values decrease, estimated proved reserve volumes are revised downward or costs incurred in exploration, development, or acquisition activities in the respective full cost pools exceed the discounted future net cash flows from the additional reserves, if any, attributable to each of the cost pools.

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 natural 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 contained in this report 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 oil and natural gas prices, drilling, operating, and production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the availability of funds.

As a result, these estimates are inherently imprecise. Ultimately, actual production, revenues, taxes, expenses, 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 contained in this Annual Report on Form 10-K to be significantly different from the actual quantities and net present value of our reserves. In addition, we may adjust our estimates of proved reserves to reflect production history, actual results, prevailing commodity prices, and other factors, many of which are beyond our control.

Further, you should not assume that any present value of future net cash flows from our proved reserves contained in this Annual Report on Form 10-K represents 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 first-day-of-month average oil and natural gas prices for the twelve-month period preceding the estimate and on costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. 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. At December 31, 2009, approximately 37% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule, and results associated with these properties may not be as estimated. 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.

Our failure to replace our reserves could result in a material decline in our reserves and production, which 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 acquire additional oil and natural gas reserves that are economically recoverable. 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. See "—*We require substantial capital expenditures to conduct our operations, engage in acquisition activities, and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy*," for a discussion of the impact of financial market conditions on our access to financing.

Drilling is a high-risk activity and may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The seismic data and other technologies that we use when drilling wells do not allow us to conclusively determine prior to drilling a well whether oil or natural gas is present or can be produced economically. As a result, we may drill new wells or participate in new wells that are dry wells or are productive but not commercially productive and, as a result, we may not recover all or any portion of our investment in the wells we drill or in which we participate.

The costs and expenses of drilling, completing, and operating wells are often uncertain. The presence of unanticipated pressures or irregularities in formations, miscalculations, or accidents may cause our drilling costs to be significantly higher than expected or cause our drilling activities to be unsuccessful or result in the total loss of our investment. Also, our drilling operations may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control, including, among others:

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

We conduct a portion of our drilling activities through a wholly owned drilling subsidiary that provides services to us and third parties. The activities conducted by the drilling subsidiary are subject to many risks, including well blow-outs, cratering and explosions, pipe failures, fires, uncontrollable flows of oil, natural gas, brine, or well fluids, other environmental hazards, and risks outside of our control, including the factors described above, and the risks associated with conducting drilling activities. Among other things, these risks include the risk of natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases, any of which could result in substantial losses, personal injuries or loss of life, severe damage to or destruction of property, natural resources, and equipment, extensive pollution or other environmental damage, clean-up responsibilities, regulatory investigations, and administrative, civil, and criminal penalties, and injunctions resulting in the suspension of our operations. If any of these risks occur, we could sustain substantial losses.

Competition within our industry is intense and may adversely affect our operations.

We operate in a highly competitive environment. We compete 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. We also compete with major and independent oil and gas companies in the marketing and sale of oil and natural gas. Many of these competitors are larger, including some of the fully integrated energy companies, have financial, staff, and other resources substantially greater than ours and may be less leveraged than we are. As a result, these companies may have greater access to capital and may be able to pay more for development prospects and producing properties, or evaluate and bid for a greater number of properties and prospects than our financial and staffing resources permit. Also, from time to time, we have to compete with financial investors in the property acquisition market, including private equity sponsors with more funds and access to additional liquidity. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and evaluate properties, available funds, and internal standards for minimum projected return on investment. In addition, while costs for equipment, service, and labor in the industry as well as the cost of properties available for acquisition tend to fluctuate with oil and gas prices, these costs often do not decrease proportionately to, or their decreases lag behind, decreases in commodity prices. This disconnect can negatively impact our cash flows and may put us at a competitive disadvantage with respect to companies that have greater financial and operational resources. In addition, oil and gas producers are increasingly facing competition from providers of non-fossil energy, and government policy may favor those competitors in the future. Many of these competitors have financial and other resources substantially greater than ours. We can give no assurance that we will be able to compete effectively in the future and that our financial condition and results of operations will not suffer as a result.

Our growth depends partly on our ability to acquire oil and gas properties on a profitable basis.

Acquisition of producing oil and gas properties has historically been a key element of maintaining and growing our 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, among others:

- 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;
- our ability to promptly integrate the new operations with existing operations;
- results of future exploitation, exploration, and development activities on the acquired properties; and
- future abandonment and possible future environmental liabilities.

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. See "*—We require substantial capital expenditures to conduct our operations, engage in acquisition activities, and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy*," for a discussion of the impact of the financial market conditions on our access to financing.

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, 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. 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. The new framework went into effect on January 1, 2009. See Part I, "Business—Regulation—*Canada*" for more detail on the Canadian regulatory framework.

In addition, our oil and gas exploration activities in Italy and South Africa may be adversely affected by political, economic, and regulatory developments, changes in the local royalty and tax regimes, and currency fluctuations.

As part of our ongoing operations, we sometimes drill in new or emerging plays. As a result, our drilling in these areas is subject to greater risk and uncertainty.

We have an internal group that is responsible for identifying new or emerging plays. These activities are more uncertain than drilling in areas that are developed and have established production. Because emerging plays and new formations have limited or no production history, we are less able to use past drilling results to help predict future results. The lack of historical information may result in not being able to fully execute our expected drilling programs in these areas, or the return on investment in these areas may turn out to not be as attractive as anticipated. We cannot assure you that our future drilling activities in Quebec or other emerging plays will be successful or, if successful, will achieve the potential resource levels that we currently anticipate based on the drilling activities that have been completed or will achieve the anticipated economic returns based on our current cost models.

Our oil and gas operations are subject to various environmental and other governmental laws and regulations that materially affect our operations.

Our oil and gas operations are subject to various U.S. federal, state, and local laws and regulations, Canadian federal, provincial, and local laws and regulations, and local and federal laws and regulations in Italy and South Africa. These laws and regulations may be changed in response to economic or political conditions. There can be no assurance that present or future regulations will not adversely affect our business and operations. See Part I, Item 1, "Business—Regulation" for detail on both current and potential governmental regulation.

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 or operate. As a result, we are subject to the risk that these facilities may be temporarily unavailable due to mechanical reasons or market conditions, or may not be available to us in the future. If we experience interruptions or loss of pipeline or access to gathering systems that impact a substantial amount of our production, it could have an adverse impact on our cash flow.

We may not be insured against all of the operating risks to which our business is 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, weather-related issues, 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 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 Restated 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.

We may face liabilities related to the pending bankruptcy of Pacific Energy Resources, Ltd.

In August 2007, we closed on the sale of our oil and gas assets in Alaska (the "Alaska Assets") to Pacific Energy Resources, Ltd ("PERL"). In March 2009, PERL filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. PERL requested, and the bankruptcy court has approved, abandonment of PERL's interests in certain of the Alaska Assets. The remaining working interest owners in the Alaska Assets previously made the assertion that, in its role as assignor of the Alaska

Assets, Forest should be held liable for any contractual obligations of PERL with respect to the Alaska Assets, including obligations related to operating costs and for costs associated with the final plugging and decommissioning of wells and production facilities. Forest disagrees with the working interest owners' assertion and, to the extent necessary, will vigorously oppose any efforts to hold Forest liable for PERL's unsatisfied obligations. We cannot predict, however, whether we would be successful in avoiding liabilities associated with PERL's unsatisfied obligations.

Item 1B. Unresolved Staff Comments.

As of December 31, 2009, 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 Annual Report on 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, 2009.

Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of February 25, 2010.

Name	Age	Years with Forest	Office[1]
H. Craig Clark	53	9	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.
Michael N. Kennedy	35	9	Executive Vice President and Chief Financial Officer since December 2009. Mr. Kennedy joined Forest in February 2001. He served as Senior Financial Analyst until April 2003, at which time he became Manager of Investor Relations. Mr. Kennedy served in that role until November 2005 when he became Managing Director of Capital Markets and Treasurer and in April 2008 assumed the role of Vice President—Finance and Treasurer. Prior to joining Forest, Mr. Kennedy worked for Arthur Andersen as a member of its audit and business advisory practice.
J.C. Ridens	54	6	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	59	21	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	53	7	Senior Vice President, Western Region since March 2009. He joined Forest as Senior Vice President, Alaska, in September 2003. Mr. Gurule served as Senior Vice President following the sale of our Alaska business in August 2007, while providing project oversight for Italy. 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	46	8	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	47	9	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.

Name	Age	Years with Forest	Office[(1)]
Victor A. Wind	36	5	Senior Vice President, Chief Accounting Officer and Corporate Controller since December 2009. Mr. Wind previously served as Vice President, Chief Accounting Officer and Corporate Controller since May 2009. He joined Forest as Corporate Controller 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.
Mark E. Bush	49	13	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.
Ronald C. Nutt	52	3	Vice President, Southern Region since July 2007. Prior to joining Forest, from March 2007 to July 2007, Mr. Nutt worked for Constellation Energy Group, and from January 2003 to March 2007 at Scotia Waterous as Vice President, Engineering.

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

PART II

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

Common Stock

Forest has one class of common shares outstanding, its common stock, par value $.10 per share ("Common Stock"). Forest's Common Stock is traded on the New York Stock Exchange under the symbol "FST." On February 19, 2010, our Common Stock was held by 588 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange composite tape. There were no cash dividends declared on the Common Stock in 2008 or 2009. On February 25, 2010, the closing price of Forest Common Stock was $26.83.

		Common Stock	
		High	Low
2008	First Quarter	$52.22	40.85
	Second Quarter	76.20	47.26
	Third Quarter	83.10	45.31
	Fourth Quarter	49.10	12.00
2009	First Quarter	$21.79	10.33
	Second Quarter	22.26	12.45
	Third Quarter	20.17	12.01
	Fourth Quarter	24.99	17.15

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 2011, Forest's 8½% 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, as amended. The provisions in the indentures pertaining to these senior notes and in the bank credit facilities limit our ability to make restricted payments, which include dividend payments. On March 2, 2006, Forest distributed a special stock dividend in connection with the spin-off of its offshore Gulf of Mexico operations; however, Forest has not paid cash dividends on its Common Stock during the past five years. The future payment of cash dividends, if any, on the Common Stock is within the discretion of the Board of Directors and will depend on Forest's earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that Forest will pay any cash dividends. For further information regarding our equity securities and our ability to pay dividends on our Common Stock, see Notes 4 and 6 to the Consolidated Financial Statements.

Unregistered Sales of Equity Securities

We did not make any sales of unregistered equity securities during 2009.

Issuer Purchases of Equity Securities

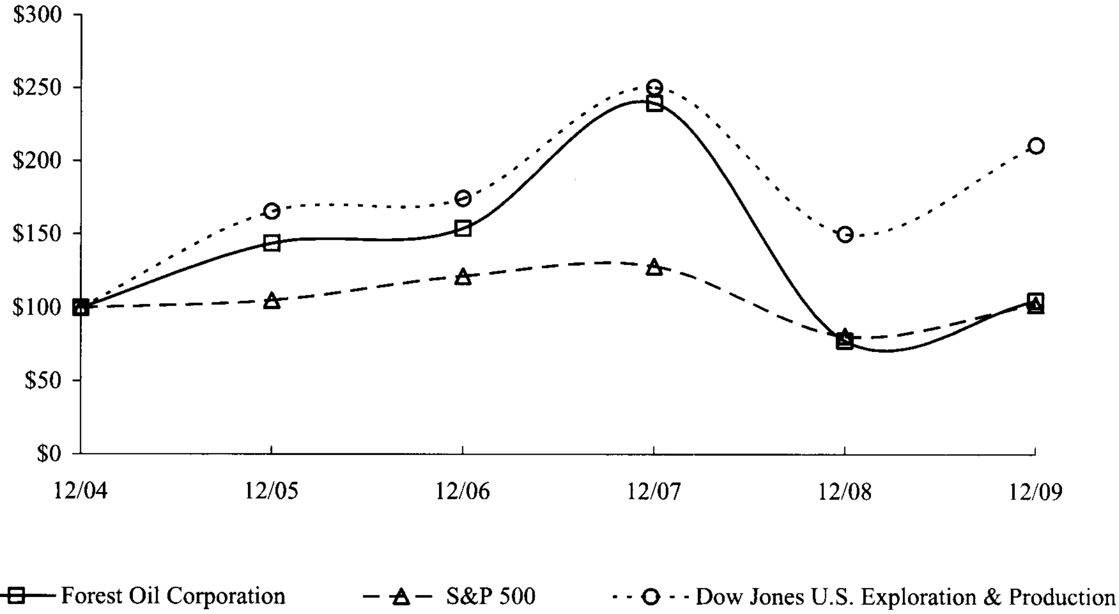
The table below sets forth information regarding repurchases of our Common Stock during the quarter ended December 31, 2009. The shares repurchased represent shares of our Common Stock that employees elected to surrender to Forest to satisfy their tax withholding obligations upon the vesting of shares of restricted stock and phantom stock units that are settled in shares. Forest does not consider this a share buyback program.

Period	Total # of Shares Purchased	Average Price Per Share	Total # of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum # (or Approximate Dollar Value) of Shares that May yet be Purchased Under the Plans or Programs
October 2009	14,840	19.99	—	—
November 2009	1,256	18.37	—	—
December 2009	5,208	22.02	—	—
Fourth Quarter Total	21,304	20.39	—	—

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2004 (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 12/31/04 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

The information in this Annual Report on Form 10-K appearing under the heading "Stock Performance Graph" is being furnished pursuant to Item 201(e) of Regulation S-K and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the 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, 2009. 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 contained elsewhere in this report. On June 6, 2007, Forest completed the acquisition of The Houston Exploration Company. 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 Note 2 to the Consolidated Financial Statements and Item 1 "Strategy—*Acquisition and Divestiture Activities*" for more information on acquisitions and divestitures.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Oil and gas sales[1]	$ 767,830	1,647,171	1,083,081	814,469	1,062,517
Earnings (loss) from continuing operations	(923,133)	(1,026,323)	169,306	166,080	151,568
Earnings from discontinued operations, net of tax[2]	—	—	—	2,422	—
Net earnings (loss)	$ (923,133)	(1,026,323)	169,306	168,502	151,568
Basic earnings (loss) per share:[3]					
Earnings (loss) from continuing operations	$ (8.85)	(11.46)	2.20	2.64	2.46
Earnings from discontinued operations, net of tax	—	—	—	.04	—
Basic earnings (loss) per common share	$ (8.85)	(11.46)	2.20	2.68	2.46
Diluted earnings (loss) per share:[3]					
Earnings (loss) from continuing operations	$ (8.85)	(11.46)	2.16	2.60	2.41
Earnings from discontinued operations, net of tax	—	—	—	.04	—
Diluted earnings (loss) per common share	$ (8.85)	(11.46)	2.16	2.64	2.41
Total assets	$3,684,690	5,282,798	5,695,548	3,189,072	3,645,546
Long-term debt	$2,022,514	2,735,661	1,503,035	1,204,709	884,807
Shareholders' equity	$1,079,154	1,672,912	2,411,811	1,434,006	1,684,522
OPERATING DATA					
Annual production:					
Gas (MMcf)	139,277	141,433	108,042	73,024	101,833
Liquids (MBbls)	7,265	8,031	7,945	8,026	10,568
Average sales price[1]:					
Gas (per Mcf)	$ 3.30	7.45	5.79	5.58	6.36
Liquids (per Bbl)	$ 42.41	73.96	57.54	50.70	39.23

(1) Includes the effects of hedging under cash flow hedge accounting in 2005 and 2006.

(2) Discontinued operations relate to the sale of the business assets of our Canadian marketing subsidiary on March 1, 2004.

(3) As discussed in Note 1 to the Consolidated Financial Statements, in June 2008, the FASB issued authoritative guidance that addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method. This guidance was effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, Forest adopted this guidance as of January 1, 2009. All prior period earnings per share data presented have been adjusted retrospectively to conform to the provisions of this guidance.

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

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

The following discussion and analysis should be read in conjunction with Forest's Consolidated Financial Statements and the Notes to Consolidated Financial Statements.

Forest is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas and natural gas liquids primarily in North America. Forest was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969.

2009 Summary and 2010 Outlook

Due to the downturn in the global economy in mid-to-late 2008, demand for oil and natural gas fell significantly, resulting in a dramatic decrease in oil and natural gas prices in 2009 as compared to 2008. For example, the average net realized price we received for natural gas in 2009 was 56% lower than the prices we received in 2008 and the average realized price we received for oil was 41% lower over the same period. As a result of the decreases in commodity prices, our reported revenues and operating cash flow in 2009 were significantly lower than they were in 2008. The decrease in commodity prices in 2009 also resulted in a decrease in the amount of our capital expenditures in 2009. Capital expenditures for the acquisition, exploration, and development of oil and gas properties were $596 million in 2009 compared to $2.8 billion in 2008. This lower level of capital expenditure activity was intended to maintain financial flexibility and sufficient liquidity to sustain our assets and operations until the margins on oil and gas production improved.

In the second half of 2008, we initiated a divestiture program targeted at selling certain non-core oil and gas properties with the primary intent to use the proceeds from the divestures to reduce outstanding debt. During 2009, we completed the majority of our divestiture program with over $1 billion of non-core property sales and used the proceeds to repay all outstanding amounts under our bank credit facilities in 2009 and to redeem all of our 7¾% Notes due 2014 in January 2010. As a result of these transactions, we enter 2010 with a significantly improved liquidity position compared to a year ago with $341 million of cash on hand as of January 31, 2010 after redeeming $150 million of our 7¾% Notes due 2014 in January 2010, $1.3 billion available under our bank credit facilities, and nearly $1 billion less debt than compared to January 31, 2009.

In 2010, we expect the volatility in oil and natural gas prices to continue to some extent, particularly in light of uncertain supply and demand fundamentals. In this environment, we elected to increase the portion of our natural gas and oil production volumes that we have hedged to cover 55% to 60% of our expected natural gas production and nearly 70% of our expected oil production. We expect full-year 2010 production to be lower than in 2009 due to the significant amount of non-core property sales in 2009 but anticipate sequential quarter-over-quarter production growth starting in the second quarter of 2010 as a result of our budgeted increase in drilling activity in 2010 in our three core areas. We also expect lower total production costs; interest costs; and depreciation, depletion, and amortization costs in 2010 as a result of our 2009 divestitures and the related reduction in outstanding debt.

Results of Operations

Forest reported a net loss of $923 million, or $8.85 per basic share, in 2009 compared to a net loss of $1.0 billion, or $11.46 per basic share, in 2008. Both years included non-cash ceiling test write-downs, which were caused by a significant decline in natural gas prices starting in the fourth quarter of 2008 through the first quarter of 2009. A $1.6 billion non-cash ceiling test write-down was recorded in the first quarter of 2009 and a $2.4 billion non-cash ceiling test write-down was recorded in the fourth quarter of 2008 (see—"Critical Accounting Policies, Estimates, Judgments and Assumptions—*Full Cost Method of Accounting*" for information on ceiling test write-downs.) Forest reported net earnings of $169 million, or $2.20 per basic share, in 2007. Forest's earnings before interest expense; income taxes; depletion, depreciation, and amortization expenses; and certain other items ("Adjusted EBITDA"), were $795 million in 2009, $1.3 billion in 2008, and $864 million in 2007. The fluctuation in Adjusted EBITDA between the periods presented was primarily driven by changes in oil and gas revenues net of realized gains and losses on oil and gas derivative instruments, each as discussed below. Adjusted EBITDA is considered a non-GAAP performance measure and reference should be made to *"Reconciliation of Non-GAAP Measures"* at the end of this Item 7 for further explanation of this performance measure, as well as a reconciliation to the most directly comparable GAAP measure.

Discussion of the components of the changes in our annual results follows. We have completed a significant number of acquisition and divestiture transactions of oil and gas properties throughout the last several years which affect comparability of the results for the years presented below. Details on our acquisition and divestiture transactions are included in Note 2 to the Consolidated Financial Statements.

Oil and Gas Production and Revenues

Oil and gas production volumes, revenues, and average sales prices, by product and location for the years ended December 31, 2009, 2008, and 2007, are set forth in the table below.

	Year Ended December 31,											
	2009				2008				2007			
	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	**Total (MMcfe)**	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	**Total (MMcfe)**	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	**Total (MMcfe)**
Production volumes:												
United States	116,029	3,397	3,012	**154,483**	118,120	3,778	3,151	**159,694**	82,963	4,504	2,381	**124,273**
Canada	23,248	626	230	**28,384**	23,313	802	300	**29,925**	25,079	793	267	**31,439**
Totals	139,277	4,023	3,242	**182,867**	141,433	4,580	3,451	**189,619**	108,042	5,297	2,648	**155,712**
Revenues (In Thousands):												
United States	$386,581	193,185	75,813	**655,579**	890,417	365,913	140,339	**1,396,669**	493,321	305,873	93,624	**892,818**
Canada	73,147	32,016	7,088	**112,251**	162,769	69,520	18,213	**250,502**	132,601	46,037	11,625	**190,263**
Totals	$459,728	225,201	82,901	**767,830**	1,053,186	435,433	158,552	**1,647,171**	625,922	351,910	105,249	**1,083,081**
Average sales price per unit:												
United States	$ 3.33	56.87	25.17	**4.24**	7.54	96.85	44.54	**8.75**	5.95	67.91	39.32	**7.18**
Canada	3.15	51.14	30.82	**3.95**	6.98	86.68	60.71	**8.37**	5.29	58.05	43.54	**6.05**
Totals	$ 3.30	55.98	25.57	**4.20**	7.45	95.07	45.94	**8.69**	5.79	66.44	39.75	**6.96**

Net oil and gas production in 2009 was 182.9 Bcfe, or an average of 501 MMcfe per day, a 4% decrease from 189.6 Bcfe, or an average of 518 MMcfe per day, in 2008. Oil and gas production decreased due to a significant reduction in drilling and acquisition activity in 2009 compared to 2008, non-core asset sales, and normal production declines on producing oil and gas properties. Oil and natural gas revenues in 2009 were $768 million, a 53% decrease as compared to $1.6 billion in 2008. The decrease in oil and natural gas revenues was due primarily to the 52% decrease in the average realized sales prices, which decreased to $4.20 per Mcfe in 2009 from $8.69 per Mcfe in 2008.

Net oil and gas production in 2008 was 189.6 Bcfe, or an average of 518 MMcfe per day, a 22% increase from 155.7 Bcfe, or an average of 427 MMcfe per day, in 2007. The net increase in oil and gas production in 2008 was primarily attributable to our active drilling and acquisition activity in 2008 as well as the acquisition of Houston Exploration in June 2007, partially offset by normal production declines on existing wells and the sale of our Alaska assets in August 2007. Oil and natural gas revenues in 2008 were $1.6 billion, a 52% increase as compared to $1.1 billion in 2007. The increase in oil and natural gas revenues was due to the 22% increase in production and a 25% increase in the average realized sales price, which increased to $8.69 per Mcfe in 2008 from $6.96 per Mcfe in 2007.

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

Oil and Gas Production Expense

The table below sets forth the detail of oil and gas production expense for the periods indicated.

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands, Except per Mcfe Data)		
Production expense:			
Lease operating expenses	$146,977	167,830	167,473
Production and property taxes	42,903	82,147	55,264
Transportation and processing costs	20,915	19,472	20,200
Production expense	$210,795	269,449	242,937
Production expense per Mcfe:			
Lease operating expenses	$ .80	.89	1.08
Production and property taxes	.23	.43	.35
Transportation and processing costs	.11	.10	.13
Production expense per Mcfe	$ 1.15	1.42	1.56

Lease Operating Expenses

Lease operating expenses were $147 million in 2009, a decrease of 12% compared to $168 million in 2008. On a per-Mcfe basis, lease operating expenses decreased 10% to $.80 per Mcfe in 2009 from $.89 per Mcfe in 2008. The decrease in total and per-Mcfe lease operating expenses was attributable to company-wide cost reduction initiatives and lower oil field service costs. Lease operating expenses in 2008 were consistent with 2007 levels, but on a per-Mcfe basis, lease operating expenses decreased 18% to $.89 per Mcfe in 2008 from $1.08 per Mcfe in 2007. The decrease in lease operating expenses on a per-Mcfe basis in 2008 as compared to 2007 was primarily due to lower average per-unit lease operating costs from the assets acquired from Houston Exploration in June 2007 and the divestiture of our Alaska assets in August 2007.

Production and Property Taxes

Production and property taxes, which primarily consist of severance taxes paid on the value of the oil and gas sold, were 5.6%, 5.0%, and 5.1% of oil and natural gas revenues for the years ended December 31, 2009, 2008, and 2007, respectively. Normal fluctuations occur in the percentage between periods based upon the timing of approval of incentive tax credits in Texas and changes in the assessed values of oil and gas properties and equipment for purposes of ad valorem taxes.

Transportation and Processing Costs

Transportation and processing costs were $21 million, or $.11 per Mcfe, in 2009, $19 million, or $.10 per Mcfe, in 2008, and $20 million, or $.13 per Mcfe, in 2007. The per-unit decrease in 2008 as compared to 2007 was primarily due to lower per-unit transportation costs recognized in 2008 as a result of the sale of our Alaska assets in August 2007.

General and Administrative Expense

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

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands, Except Per Mcfe Data)		
Stock-based compensation costs	$ 29,165	27,012	17,681
Other general and administrative costs	88,935	95,002	89,697
General and administrative costs capitalized	(47,024)	(47,282)	(43,627)
General and administrative expense	$ 71,076	74,732	63,751
General and administrative expense per Mcfe	$ .39	.39	.41

General and administrative expense decreased approximately $4 million to $71 million in 2009 from $75 million in 2008. General and administrative expense increased $11 million in 2008 compared to 2007, which was primarily related to increased stock-based compensation as well as increased employee salary and benefit costs and rent expense associated with having a full-year of additional personnel added as a result of the acquisition of Houston Exploration in June 2007. The percentage of general and administrative costs capitalized under the full cost method of accounting remained relatively constant between the three years, ranging between 39% and 41%.

Forest recorded stock-based compensation cost in the amount of $29 million in 2009, $27 million in 2008, and $18 million in 2007. The increase in stock-based compensation of $9 million in 2008 from 2007 was primarily due to stock-based awards granted in 2008.

Depreciation, Depletion, and Amortization

The following table summarizes depreciation, depletion, and amortization expense incurred during the periods indicated.

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands, Except Per Mcfe Data)		
Depreciation, depletion, and amortization expense	$303,622	532,181	390,338
Depreciation, depletion, and amortization expense per Mcfe	$ 1.66	2.81	2.51

Depreciation, depletion, and amortization expense ("DD&A") decreased $1.15 per Mcfe to $1.66 in 2009 compared to $2.81 in 2008 primarily due to a $2.4 billion non-cash ceiling test write-down recorded in the fourth quarter 2008 and a $1.6 billion non-cash ceiling test write-down recorded in the first quarter 2009. DD&A increased $.30 per Mcfe in 2008 compared to 2007 primarily due to price-related negative reserve revisions during 2008 caused by a decrease in oil and gas prices at December 31, 2008 compared to December 31, 2007, as well as the acquisition of Houston Exploration in June 2007.

Accretion of Asset Retirement Obligations

Accretion expense of $8 million in 2009 and 2008 and $6 million in 2007 was related to the accretion of Forest's asset retirement obligations. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred along with a corresponding increase in the carrying amount of the related long-lived asset. Subsequent to initial measurement, the asset retirement obligation is accreted each period to its present value. See Note 1 to the Consolidated Financial Statements for additional information on our asset retirement obligations.

Ceiling Test Write-Down of Oil and Gas Properties

Pursuant to the ceiling test limitation prescribed by the Securities and Exchange Commission ("SEC") for companies using the full cost method of accounting, Forest recorded a non-cash ceiling test write-down for both its United States and Canadian cost centers totaling $1.6 billion in the first quarter 2009. In the fourth quarter of 2008, Forest recorded a $2.4 billion non-cash ceiling test write-down for its United States cost center. The write-downs were a result of significant declines in oil and natural gas prices in the fourth quarter of 2008 and the first quarter of 2009. See—"Critical Accounting Policies, Estimates, Judgments and Assumptions—*Full Cost Method of Accounting*" and Part II, Item 1A,—"Risk Factors—*Lower oil and gas prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values.*"

Interest Expense

The following table summarizes interest expense incurred during the periods indicated.

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
Interest costs	$175,662	143,534	127,063
Interest costs capitalized	(12,175)	(17,855)	(13,901)
Interest expense	$163,487	125,679	113,162

Interest expense in 2009 totaled $163 million compared to $126 million in 2008. The $38 million increase in interest expense was primarily due to an increase in average debt levels in 2009 compared to 2008 which was primarily attributable to the use of debt to fund the $570 million cash portion of the acquisition of oil and gas assets from Cordillera Texas, L.P. in September 2008. Interest expense in 2008 totaled $126 million compared to $113 million in 2007. The $13 million increase in interest expense was primarily due to increased interest expense on the credit facilities, which was caused by higher average borrowings throughout the year, offset somewhat by lower interest rates. Interest expense also increased in 2008 compared to 2007 due to the $750 million of senior notes that were issued in June 2007 in conjunction with the Houston Exploration acquisition. Interest costs that are capitalized relate to significant unproved acreage positions that are under development.

Realized and Unrealized Gains and Losses on Derivative Instruments

The table below sets forth realized and unrealized gains and losses on derivatives recognized under "Costs, expenses, and other" in our Consolidated Statements of Operations for the periods indicated.

See Note 9 and Note 10 to the Consolidated Financial Statements for more information on our derivative instruments.

	Year Ended December, 31		
	2009	2008	2007
	(In Thousands)		
Realized (gains) losses on derivatives, net:			
Oil[1]	$ (11,632)	71,198	(2,587)
Gas[2]	(285,576)	(16,126)	(72,904)
Interest	(10,958)	889	(474)
Subtotal realized	(308,166)	55,961	(75,965)
Unrealized losses (gains) on derivatives, net:			
Oil	35,771	(118,151)	123,099
Gas	139,728	(98,618)	(10,321)
Interest	519	(4,721)	4,721
Subtotal unrealized	176,018	(221,490)	117,499
Realized and unrealized (gains) losses on derivatives, net	$(132,148)	(165,529)	41,534

(1) Includes total proceeds of $7 million received in 2007 upon termination of two oil swaps, which collectively covered 1,000 Bbl per day for 2009 and 500 Bbl per day for 2010.

(2) Includes total proceeds of $19 million received in 2008 upon termination of two gas swaps and one gas collar, which collectively covered 40 Bbtu per day for 2009.

Gain on Sale of Assets

In 2008, Forest sold all of its unproved oil and gas properties in Gabon for $24 million, which resulted in a gain of $21 million. In 2007, Forest sold its overriding royalty interests in unproved oil and gas properties in Australia for net proceeds of $7 million, which resulted in a gain of $7 million.

Other, Net

The table below sets forth the components of "Other, net" in our Consolidated Statements of Operations for the periods indicated.

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
Unrealized losses on other investments, net	$ 2,327	34,042	4,948
Unrealized foreign currency exchange (gains) losses, net	(17,974)	19,481	(7,694)
Realized foreign currency exchange (gains) losses, net	(88)	959	(7,721)
Rig stacking costs	8,940	—	—
Debt extinguishment costs	—	97	12,215
Franchise taxes	1,410	1,612	2,322
Other, net	6,462	3,464	154
	$ 1,077	59,655	4,224

Unrealized Losses on Other Investments

Unrealized losses on other investments relate to fair value adjustments to the shares of Pacific Energy Resources, Ltd. ("PERL") common stock and the zero coupon senior subordinated note from PERL due 2014, which were received as a portion of the total consideration for the sale of our Alaska assets in August 2007. In March 2009, PERL filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code and subsequently indicated that the value of its assets is less than the amount of its senior unsubordinated debt. As such, we estimated the fair value of the PERL common stock and the subordinated note to be zero as of December 31, 2009. See Note 2 and Note 9 to the Consolidated Financial Statements for more information on these investments.

Foreign Currency Exchange

Realized and unrealized foreign currency exchange gains and losses relate to outstanding intercompany indebtedness and advances, which are denominated in U.S. dollars, between Forest Oil Corporation and our wholly-owned Canadian subsidiary.

Rig Stacking Costs

Rig stacking costs represent expenses incurred related to drilling rigs that are not being used. These expenses include items such as drilling rig contract buyouts related to third party operated rigs and costs related to internally operated rigs such as rig rental costs and property taxes.

Debt Extinguishment Costs

Debt extinguishment costs in 2007 related to the complete repayment of the Alaska Credit Agreements and included $5 million in prepayment premiums and $7 million of unamortized debt issue costs.

Franchise Taxes

Franchise taxes are taxes paid to various states based on capital investment deployed in those states, determined by apportioning total capital as defined by statute.

Income Tax

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

	Year Ended December 31,		
	2009	**2008**	**2007**
	(In Thousands, Except Percentages)		
Current income tax	$ 70,815	11,139	5,999
Deferred income tax	(581,290)	(585,817)	56,396
Total income tax	$(510,475)	(574,678)	62,395
Effective tax rate	36%	36%	27%

Our combined U.S. and Canadian effective tax rate generally approximates 35% to 36% but will fluctuate based on the percentage of pre-tax income generated in the U.S. versus Canada. Our effective rate in 2007 was 27% due to a reduction in income taxes of approximately $21 million related to statutory rate reductions enacted in Canada, the release of valuation allowances, and a lower apportioned effective state income tax rate. The current provision for income taxes increased to $71 million in 2009 due primarily to $933 million in asset sales in the United States which contributed to taxable income in excess of our remaining available net operating loss carryforwards. 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.

Liquidity and Capital Resources

Our exploration, development, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and our bank credit facilities as our primary sources of liquidity. To fund large and other exceptional transactions, such as acquisitions and debt refinancing transactions, we have looked to the private and public capital markets as another source of financing and, as market conditions have permitted, we have engaged in asset monetization transactions.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. Natural gas is expected to make up approximately 80% of our oil and gas production in 2010 and, as a result, our operations and cash flow are more sensitive to fluctuations in the market price for natural gas than to fluctuations in the market price for oil. We employ a commodity hedging strategy as an attempt to moderate the effects of wide fluctuations in commodity prices on our cash flow. As of February 25, 2010, we had hedged, via commodity swaps and collar instruments, approximately 84 Bcfe of our total 2010 production. This level of hedging will provide a measure of certainty of the cash flow that we will receive for a portion of our production in 2010. However, these hedging activities may result in reduced income or even financial losses to us. See Part I, Item 1A,—"Risk Factors—*Our use of hedging transactions could result in financial losses or reduce our income*," for further details of the risks associated with our hedging activities. In the future, we may determine to increase or decrease our hedging positions. As of February 25, 2010, all of our derivatives counterparties are commercial banks that are parties to our credit facilities, or their affiliates, with the exception of one counterparty with whom we hold basis swaps. For further information concerning our derivative contracts, see Part II, Item 7A—"Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk," below.

The other primary source of liquidity is our combined U.S. and Canadian credit facilities, which had an aggregated borrowing base of $1.3 billion as of December 31, 2009. These facilities are used to fund daily operations and to fund acquisitions and refinance debt, as needed and if available. The credit facilities are secured by a portion of our assets and mature in June 2012. See—"*Bank Credit Facilities*" below for further details. We had no amounts drawn on our credit facilities as of December 31, 2009 and February 25, 2010.

The public and private capital markets have served as our primary source of financing to fund large acquisitions and other exceptional transactions. In the past, we have issued debt and equity in both the public and private capital markets. For example, in February 2009, we issued $600 million principal amount of 8½% senior notes due 2014 in a private offering for net proceeds of $560 million and in May 2009, we issued approximately 14 million shares of common stock for net proceeds of $256 million. Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the domestic and global financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of our equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control.

We also have engaged in asset dispositions as a means of generating additional cash to fund expenditures and enhance our financial flexibility. For example, during 2009, we sold certain non-strategic assets for approximately $1.1 billion, a portion of which proceeds were used to pay off the outstanding balances under our credit facilities in 2009 and redeem our 7¾% Senior Notes due 2014 in January 2010.

We believe that our current cash and cash equivalents, cash flows provided by operating activities, and $1.3 billion of funds available under our credit facilities will be sufficient to fund our normal recurring operating needs, anticipated capital expenditures, and our contractual obligations. However, if our revenue and cash flow decrease in the future as a result of a deterioration in domestic and global economic conditions or a significant decline in commodity prices, we may elect to reduce our planned capital expenditures. We believe that this financial flexibility to adjust our spending levels will provide us with sufficient liquidity to meet our financial obligations should economic conditions deteriorate. See Part I, Item 1A—"Risk Factors," for a discussion of the risks and uncertainties that affect our business and financial and operating results.

Bank Credit Facilities

Our bank credit facilities consist of a $1.65 billion U.S. credit facility (the "U.S. Facility") with 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") with a syndicate of banks led by JPMorgan Chase Bank, N.A., Toronto Branch. The Credit Facilities will mature in June 2012. Our availability under the Credit Facilities is governed by a borrowing base (the "Global Borrowing Base"). The determination of the Global Borrowing Base is made by the lenders in their sole discretion, on a semi-annual basis, taking into consideration the estimated value of our oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. The available borrowing amount under the Credit Facilities could increase or decrease based on such redetermination. The next redetermination of the borrowing base is expected to occur in the second quarter of 2010. In addition to the semi-annual redeterminations, Forest and the lenders each have discretion at any time, but not more often than once during a calendar year, to have the Global Borrowing Base redetermined.

The Global Borrowing Base is also subject to change in the event (i) we issue senior notes, in which case the Global Borrowing Base will immediately be reduced by an amount equal to $0.30 for every $1.00 principal amount of any newly issued senior notes, excluding any senior notes that we may issue to refinance senior notes that were outstanding on May 9, 2008 or (ii) if we sell oil and natural gas properties included in the Global Borrowing Base having a fair market value in excess of 10% of the Global Borrowing Base then in effect. The Global Borrowing Base is subject to other automatic adjustments under the facilities. As a result of issuing $600 million of 8½% senior notes due 2014 in February 2009, our borrowing base was lowered from $1.8 billion to $1.62 billion effective February 17, 2009 and as a result of the sale of certain oil and gas properties in December 2009, our borrowing base was lowered from $1.62 billion to $1.3 billion effective December 21, 2009. As a result of the December adjustment, we reallocated amounts under the U.S. Facility and Canadian Facility and currently have allocated $1.155 billion to the borrowing base under the U.S. Facility and $145 million to the borrowing base under the Canadian Facility. A lowering of the Global Borrowing Base could require us to repay indebtedness in excess of the Global Borrowing Base in order to cover the deficiency. The automatic lowering of the Global Borrowing Base on February 17, 2009 and again on December 21, 2009 did not result in any deficiency, and therefore we were not required to repay any amounts.

Borrowings under the U.S. Facility bear interest at one of two rates as may be elected by us. Borrowings bear interest at:

(i) a rate that is based on interest rates applicable to dollar deposits in the London interbank market ("LIBO Rate") plus 100 to 175 basis points, depending on Global Borrowing Base utilization; or

(ii) a rate based on the greatest of (a) the prime rate announced by the global administrative agent; (b) the federal funds rate plus ½ of 1%; and (c) the Adjusted LIBO Rate for a one month Interest Period on such day plus 100 basis points.

Borrowings under the Canadian Facility bear interest at one of three rates as may be elected by us. Borrowings bear interest at a rate that may be based on:

(i) the greatest of (a) the base rate announced by the Canadian administrative agent with respect to Canadian dollar loans, and (b) the sum of (x) a bankers acceptance rate and (y) 100 basis points;

(ii) the LIBO Rate plus 100 to 175 basis points, depending on Global Borrowing Base utilization; or

(iii) the greater of (a) the rate for U.S. dollar denominated loans made by the Canadian administrative agent and (b) the federal funds rate plus ½ of 1%.

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 also include financial covenants. For example, the Credit Facilities provide that we will not permit our ratio of total debt outstanding to our EBITDA (as adjusted for non-cash charges) to be greater than (i) 4.50 to 1.00 for four consecutive fiscal quarters ending in 2009 and 2010; (ii) 4.00 to 1.00 for four consecutive fiscal quarters ending in 2011; and (iii) 3.50 to 1.00 at any time thereafter. If we were to fail to perform our obligations under these covenants or other covenants and obligations, it could cause an event of default and the Credit Facilities could be terminated and amounts outstanding could be declared immediately due and payable by the lenders, subject to notice and cure periods in certain cases. Such events of default include non-payment, breach of warranty, non-performance of 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. In addition, 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. An acceleration of our indebtedness under the Credit Facilities could in turn result in an event of default under the indentures for our senior notes, which in turn could result in the acceleration of the senior notes.

Under the Credit Facilities, we are required to mortgage and grant a security interest in the greater of 75% of the present value of our consolidated proved oil and gas properties, or 1.875 multiplied by the allocated U.S. borrowing base. We also are required to and have pledged the stock of several subsidiaries to the lenders to secure the Credit Facilities. Under certain circumstances, we could be obligated to pledge additional assets as collateral. If our corporate credit ratings assigned by Moody's and S&P improve and meet pre-established levels, the collateral requirements would cease to apply and, at our request, the banks would release their liens and security interests on our properties. In addition to these collateral requirements, one of our subsidiaries, Forest Oil Permian Corporation, is a subsidiary guarantor of the Credit Facilities.

Of the $1.8 billion total nominal amount under the Credit Facilities, JPMorgan and seven other banks hold approximately 62% of the total commitments, with each of these eight lenders holding an equal share. With respect to the other 38% of the total commitments, no single lender holds more than 4.6% of the total commitments.

From time to time, we engage in other transactions with a number of the lenders under the Credit Facilities. Such lenders or their affiliates may serve as underwriters or initial purchasers of our debt and equity securities, act as agent or directly purchase our production, or serve as counterparties to our commodity and interest rate derivative agreements. As of February 25, 2010, our primary derivative counterparties are lenders and their affiliates, with six such lenders accounting for approximately 76 Bcfe, or 90% of our 2010 hedged production. Our obligations under our existing derivative agreements with our lenders are secured by the security documents executed by the parties under our

Credit Facilities. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk," below for additional details concerning our derivative arrangements.

As of December 31, 2009 and February 25, 2010, there were no outstanding borrowings under our Credit Facilities. The Company had used the Credit Facilities for approximately $3.8 million in letters of credit at December 31, 2009.

Credit Ratings

Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate each series of our senior notes and, in addition, they have assigned Forest a general credit rating. Our Credit Facilities include provisions that are linked to our credit ratings. For example, our collateral requirements will vary based on our credit ratings; however, we do not have any credit rating triggers that would accelerate the maturity of amounts due under credit facilities or the debt issued under the indentures for our senior notes. The indentures for our senior notes also include terms linked to our credit ratings. These terms allow us greater flexibility if our credit ratings improve to investment grade and other tests have been satisfied, in which event we would not be obligated to comply with certain restrictive covenants included in the indentures. Our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Historical Cash Flow

Net cash provided by operating activities, net cash provided (used) by investing activities, net cash (used) provided by financing activities, and adjusted discretionary cash flow for the years ended December 31, 2009, 2008, and 2007 were as follows:

	Year Ended December 31,		
	2009	2008	2007
		(In Thousands)	
Net cash provided by operating activities	$ 596,996	1,070,040	708,245
Net cash provided (used) by investing activities	385,372	(2,093,493)	(1,093,221)
Net cash (used) provided by financing activities	(516,864)	1,016,258	359,552
Adjusted discretionary cash flow	$ 637,847	1,125,400	741,978

Net cash provided by operating activities is primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivative contracts, and changes in working capital. The decrease in net cash provided by operating activities of $473 million in 2009 as compared to 2008 was primarily due to lower commodity prices partially offset by a decreased investment in net operating assets (i.e., working capital) in 2009 as compared to 2008. The increase in net cash provided by operating activities of $362 million in 2008 as compared to 2007 was primarily due to higher production volumes and commodity prices in 2008 as compared to 2007.

Net cash provided (used) by investing activities is primarily comprised of the acquisition, exploration, and development of oil and gas properties net of dispositions of oil and gas properties. The $2.5 billion fluctuation in investing cash flows between 2009 and 2008 was primarily due to a $1.7 billion decrease in cash used for the acquisition, exploration, and development of oil and gas properties and a $744 million increase in proceeds from the sale of oil and gas properties. The increase in net cash used by investing activities in 2008 as compared to 2007 was primarily due to increased acquisition, exploration, and development expenditures in 2008 and a decrease in the proceeds from asset sales in 2008. See "*Capital Expenditures*" below for more detail on our capital expenditures. The major components of cash provided (used) by investing activities for the years ended December 31, 2009, 2008, and 2007 were as follows:

	Year Ended December 31,		
	2009	2008	2007
		(In Thousands)	
Acquisition, exploration, and development of oil and gas properties[1]	$ (637,831)	(2,338,488)	(1,563,100)
Proceeds from sale of assets	1,054,062	309,940	502,048
Acquisition of other fixed assets	(30,887)	(66,005)	(32,169)
Other	28	1,060	—
Net cash provided (used) by investing activities	$ 385,372	(2,093,493)	(1,093,221)

(1) Cash paid for exploration, development, and acquisition costs as reflected in the Consolidated Statement of Cash Flows differs from the reported capital expenditures in the "*Capital Expenditures*" table below due to the timing of when the capital expenditures are incurred and when the actual cash payment is made.

Net cash used by financing activities of $517 million in 2009 primarily included net repayments of bank borrowings of $1.3 billion, partially offset by net proceeds of $560 million for the issuance of 8½% senior notes due 2014 and net proceeds of $256 million for the issuance of common stock. Net cash provided by financing activities of $1.0 billion in 2008 primarily included net proceeds from bank borrowings of $1.0 billion, the issuance of additional 7¼% senior notes due 2019 for net proceeds of $247 million, and the redemption of our 8% senior notes due 2008 of $265 million. Net cash provided by financing activities of $360 million in 2007 primarily included the issuance of the 7¼% senior notes due 2019 for net proceeds of $739 million offset by the repayment of the Alaska credit agreements of $375 million.

Adjusted discretionary cash flow, which is a non-GAAP liquidity measure that management uses to evaluate cash flow from operations before changes in working capital such as accounts receivable, accounts payable, and accrued liabilities, was $638 million, $1.1 billion, and $742 million for 2009, 2008 and 2007, respectively. The fluctuations in adjusted discretionary cash flow between the periods presented were primarily driven by changes in oil and gas revenues net of realized gains and losses on oil and gas derivative instruments. Reference should be made to "*Reconciliation of Non-GAAP Measures*" at the end of Item 7 for further explanation of this non-GAAP liquidity measure.

Capital Expenditures

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

	Year Ended December 31,		
	2009	2008	2007
		(In Thousands)	
Property acquisitions:			
Proved properties	$ —	804,616	1,744,093
Unproved properties	—	566,952	449,346
	—	1,371,568	2,193,439
Exploration:			
Direct costs	175,960	329,897	137,475
Overhead capitalized	17,682	18,304	10,722
	193,642	348,201	148,197
Development:			
Direct costs	373,144	1,017,362	622,466
Overhead capitalized	29,342	28,978	32,905
	402,486	1,046,340	655,371
Total capital expenditures(1)	$596,128	2,766,109	2,997,007

(1) Total capital expenditures include cash expenditures, accrued expenditures, and non-cash capital expenditures including the value of Forest common stock issued in connection with property acquisitions and stock-based compensation capitalized under the full cost method of accounting. (See Note 2 to the Consolidated Financial Statements for information on property acquisitions.) Total capital expenditures also include estimated discounted asset retirement obligations of $3 million, $15 million, and $38 million recorded during the years ended December 31, 2009, 2008, and 2007, respectively.

Due to the significant downturn in the overall economy in late 2008 and its impact on the price for oil and natural gas, we chose to significantly reduce our capital expenditures and drilling activity in 2009 by keeping our exploration and development capital spending near our discretionary cash flow in 2009. As a result of significantly increased liquidity in 2010 from our non-core 2009 divestiture program, higher commodity prices, and focusing our development primarily on three core areas with expected high growth potential, we intend to increase our drilling activity in 2010 and have established a capital budget of $600 million to $700 million for the year ending December 31, 2010. Primary factors impacting the level of our capital expenditures 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, 2009:

	2010	2011	2012	2013	2014	After 2014	Total
				(In Thousands)			
Bank debt[1]	$ 2,955	2,955	1,272	—	—	—	7,182
Senior notes[2]	297,147	430,358	123,508	123,616	678,875	1,323,229	2,976,733
Operating leases[3]	19,082	17,451	16,420	15,240	9,117	4,890	82,200
Unconditional purchase obligations[4]	26,622	4,741	106	1,759	—	—	33,228
Other liabilities[5]	8,883	15,398	11,616	10,970	8,722	75,493	131,082
Derivative liabilities[6]	41,358	279	267	250	30	—	42,184
Total contractual obligations	$396,047	471,182	153,189	151,835	696,744	1,403,612	3,272,609

(1) Bank debt consists of commitment fees and letter of credit fees on the Credit Facilities based on the letters of credit outstanding and the Global Borrowing Base as of December 31, 2009. There were no outstanding bank debt borrowings as of December 31, 2009.

(2) Senior notes consist of the principal obligations on our senior notes and senior subordinated notes and anticipated interest payments due on each. The 7¾% senior notes due 2014 are included in 2010 since we irrevocably called them in December 2009 and redeemed them in January 2010.

(3) Operating leases consist of leases for drilling rigs, compressors, office facilities and equipment, and vehicles.

(4) Unconditional purchase obligations consist primarily of firm commitments for pipe and seismic purchases 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 commodity and interest rate derivatives as of December 31, 2009. 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.

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 2017, totaled approximately $6 million as of December 31, 2009.

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, 2009, 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 or 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 25, 2010, 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 $11 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 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. We have historically updated our quarterly depletion calculations with our quarter-end reserves estimates. Based on this accounting policy, our December 31, 2009 reserves estimates were used for our fourth quarter 2009 depletion calculation. These reserves estimates were calculated in accordance with the SEC's "Modernization of Oil and Gas Reporting" rules, which were first effective for 2009 year-end reporting. See Part I, Item 1, "Business—Reserves" and Note 17 to the Consolidated Financial Statements for a more complete discussion of these rules and our estimated proved reserves as of December 31, 2009.

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 for each cost center. The full cost ceiling test is a limitation on capitalized costs prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is not a fair value based measurement. Rather, it is a standardized mathematical calculation. 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. 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 write-down is required. Forest recorded a $1.6 billion non-cash ceiling test write-down in the first quarter of 2009 based on the March 31, 2009 spot prices for natural gas and oil of $3.63 per MMBtu and $49.66 per barrel, respectively. Forest recorded a $2.4 billion non-cash ceiling test write-down in the fourth quarter of 2008 based on December 31, 2008 spot prices for natural gas and oil of $5.71 per MMBtu and $44.60 per barrel, respectively. Our December 31, 2009 ceiling test calculation, which included a ceiling based on oil and gas reserves calculated using twelve-month average prices pursuant to the SEC's "Modernization of Oil and Gas Reporting" rules which were effective for the first time as of December 31, 2009, did not result in a ceiling test write-down.

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. Investments in unproved properties are not depleted pending the determination of the existence of proved reserves. 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. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Where it is not practicable to individually assess properties whose 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.

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.

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.

Goodwill

Goodwill is tested for impairment on at least an annual basis in the second quarter of the year. In addition, we test goodwill for impairment if events or circumstances change between annual tests indicating a possible impairment.

In the first step of testing for goodwill impairment, we estimate the fair value of each reporting unit, which we have determined to be our geographic operating segments, and compare the fair value with the carrying value of the net assets assigned to each reporting unit. If the fair value of a reporting unit is greater than the carrying value of the net assets assigned to the reporting unit, then no impairment results. If the fair value is less than its carrying value, then we would perform a second step and determine the fair value of the goodwill. In this second step, the fair value of goodwill is determined by deducting the fair value of a reporting unit's identifiable assets and liabilities from the fair value of the reporting unit as a whole, as if that reporting unit had just been acquired and the purchase price were being initially allocated. If the fair value of the goodwill is less than its carrying value for a reporting unit, an impairment charge would be recorded to earnings in our Consolidated Statement of Operations.

To determine the fair value of each of our reporting units, we use a discounted cash flow model to value our total estimated reserves, which include proved, probable, and possible reserves. This approach relies on significant judgments about the quantity of reserves, the timing of the expected production, the pricing that will be in effect at the time of production, and the appropriate discount rates to be used. Our discount rate assumptions are based on an assessment of Forest's weighted average cost of capital.

We did not record an impairment charge as a result of our goodwill impairment test in the second quarter of 2009 and no events or circumstances have occurred since then that have indicated a possible impairment, requiring an updated test. Based on the test we performed in the second quarter of 2009, we do not have any reporting units that are reasonably likely to fail the first step in a future goodwill impairment test. However, due to the significant judgments that go into the test, as discussed above, there can be no assurance that our goodwill will not be impaired at any time in the future.

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 uncertainty 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 17 to the Consolidated Financial Statements.

Reference should be made to "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 estimates*," under Part I, Item 1A—"Risk Factors," in this Annual Report on Form 10-K.

Accounting for Derivative Instruments

We recognize all derivative instruments as either assets or liabilities at fair value. Under the provisions of authoritative derivative accounting guidance, 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, because 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. We have elected not to use hedge accounting and as a result, all changes in the fair values of our derivative instruments are recognized in earnings as unrealized gains or losses in "Realized and unrealized gains or losses on derivative instruments, net" in our Consolidated Statements of Operations.

Estimating the fair values of our derivative instruments requires substantial judgment. We use the income approach in determining the fair value of our derivative instruments, utilizing present value techniques for valuing our swaps and basis swaps and option-pricing models for valuing our collars. Inputs to these valuation techniques include published forward prices, volatilities, and credit risk considerations, including the incorporation of published interest rates and credit spreads. The values we report in our financial statements change as these estimates are revised to reflect 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, 2009 would decrease the net fair value of our commodity derivative instruments at December 31, 2009 by approximately $53 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, 2009 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 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 earnings 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 need for a valuation allowance on our deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon whether future book income is sufficient to reverse existing temporary differences that give rise to deferred tax assets, as well as whether future taxable income is sufficient to utilize net operating loss and credit carryforwards. Assessing the need for, or the sufficiency of, a valuation allowance requires the evaluation of all available evidence, both negative and positive. Negative evidence considered by management primarily included a recent history of book losses which were driven entirely from ceiling test write-downs, which are not fair value based measurements. Positive evidence considered by management included forecasted book income over a reasonable period of time and the utilization of substantially all of our net operating loss ("NOL") carryforwards in 2009 due primarily to a substantial tax gain associated with the sale of nearly $1 billion in U.S. oil and gas assets. Based upon the evaluation of what management determined to be relevant evidence, we have recorded a $2 million valuation allowance against our U.S. deferred tax assets as of December 31, 2009. See Note 5 to the Consolidated Financial Statements.

The primary evidence utilized to determine that it is more likely than not that our deferred tax assets will be realized was management's expectation of future book income over the next several years, as well as the significant tax gain recognized in connection with the sale of our Permian assets during 2009, which allowed us to realize the majority of our deferred tax assets that were attributable to NOL carryforwards. With all of our NOL carryforwards substantially used, our deferred tax asset position is now almost exclusively driven by the accelerated reduction in the book value of our oil and gas assets relative to our tax basis due to the use of the full cost method of accounting for oil and gas properties. Under this method of accounting, we have recorded $3.9 billion in ceiling test write-downs of the book value of our oil and properties over the last two years and, even though we recorded significant tax gains on the sale of our Permian assets in 2009, no book gain was recognized for this sale under the full cost method of accounting. While both of these factors have significantly contributed to the substantial reduction in the book value of our oil and gas properties, and therefore to the recognition of a net deferred tax asset, they have also substantially reduced our prospective depletion rate, making future book income, and therefore the reversal of book to tax temporary differences, more likely than would be the case had these ceiling test write-downs and asset sales not occurred.

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") 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 January 2010, the FASB issued Accounting Standards Update ("ASU") No. 2010-06, "Improving Disclosures about Fair Value Measurements." This ASU amends existing authoritative guidance to require additional disclosures regarding fair value measurements, including the amounts and reasons for significant transfers between Level 1 and Level 2 of the fair value hierarchy, the reasons for any transfers into or out of Level 3 of the fair value hierarchy, and presentation on a gross basis of information regarding purchases, sales, issuances, and settlements within the Level 3 rollforward. This ASU also clarifies certain existing disclosure requirements. The guidance within this ASU is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements within the Level 3 rollforward, which are effective for interim and annual reporting periods beginning after December 15, 2010. The adoption of this authoritative guidance will have no impact on our financial position or results of operations, but may require expanded disclosure about fair value measurements.

Reconciliation of Non-GAAP Measures

Adjusted EBITDA

In addition to reporting net earnings as defined under generally accepted accounting principles ("GAAP"), Forest also presents adjusted earnings before interest, taxes, depreciation, depletion, and amortization ("Adjusted EBITDA"), which is a non-GAAP performance measure. Adjusted EBITDA consists of net earnings (loss) before interest expense, income taxes, depreciation, depletion, and amortization, as well as other non-cash operating items such as ceiling test write-downs of oil and gas properties, unrealized losses (gains) on derivative instruments, unrealized and realized foreign currency exchange (gains) losses, unrealized losses on other investments, accretion of asset retirement obligations, and other items presented in the table below. Adjusted EBITDA does not represent and should not be considered an alternative to GAAP measurements, such as net earnings (its most comparable GAAP financial measure), and Forest's calculations thereof may not be comparable to similarly titled measures reported by other companies. By eliminating interest, income taxes, depreciation, depletion, amortization, and other items, Forest believes the result is a useful measure across time in evaluating its fundamental core operating performance. Management also uses Adjusted EBITDA to manage its business, including in preparing its annual operating budget and financial projections. Forest believes that Adjusted EBITDA is also useful to investors because similar measures are frequently used by securities analysts, investors, and other interested parties in their evaluation of companies in similar industries. As indicated, Adjusted EBITDA does not include interest expense on borrowed money or depletion and depreciation expense on capital assets or the payment of income taxes, which are necessary elements of Forest's operations. Because Adjusted EBITDA does not account for these and other expenses, its utility as a measure of Forest's operating performance has material limitations. Because of these limitations, Forest's management does not view Adjusted EBITDA in isolation and also uses other measurements, such as net earnings and revenues to measure operating performance. The following table provides a reconciliation of net earnings (loss), the most directly comparable GAAP measure, to Adjusted EBITDA for the periods presented.

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
Net earnings (loss)	$ (923,133)	(1,026,323)	169,306
Income tax (benefit) expense	(510,475)	(574,678)	62,395
Unrealized losses (gains) on derivative instruments, net	176,018	(221,490)	117,499
Unrealized foreign currency exchange (gains) losses, net	(17,974)	19,481	(7,694)
Unrealized losses on other investments, net	2,327	34,042	4,948
Realized foreign currency exchange (gains) losses, net	(88)	959	(7,721)
Interest expense	163,487	125,679	113,162
Debt extinguishment costs	—	97	12,215
Accretion of asset retirement obligations	8,311	7,602	6,064
Ceiling test write-down of oil and gas properties	1,575,843	2,369,055	—
Depreciation, depletion, and amortization	303,622	532,181	390,338
Stock-based compensation	16,779	17,171	10,895
Gain on sale of assets	—	(21,063)	(7,176)
Adjusted EBITDA	$ 794,717	1,262,713	864,231

Discretionary Cash Flow

In addition to reporting cash provided by operating activities as defined under GAAP, Forest also presents adjusted discretionary cash flow, which is a non-GAAP liquidity measure. Adjusted discretionary cash flow consists of cash provided by operating activities before changes in working capital items and current income taxes associated with oil and gas property divestitures. Management uses adjusted discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. This measure does not represent the residual cash flow available for discretionary expenditures, since Forest has mandatory debt service requirements and other non-discretionary expenditures that are not deducted from the measure. The following table provides a reconciliation of cash provided by operating activities, the most directly comparable GAAP measure, to adjusted discretionary cash flow for the periods presented.

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
Net cash provided by operating activities	$596,996	1,070,040	708,245
Changes in working capital and other items:			
Accounts receivable	(35,790)	(42,854)	(353)
Other current assets	(30,809)	80,214	(1,557)
Accounts payable and accrued liabilities	47,956	(15,796)	9,592
Accrued interest and other current liabilities	(12,077)	30,686	26,051
Current income taxes on oil and gas property divestitures	71,571	3,110	—
Adjusted discretionary cash flow	$637,847	1,125,400	741,978

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

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

Commodity Price Risk

We produce and sell natural gas, crude oil, and natural gas liquids for our own account in the United States and Canada. As a result, our financial results are affected when prices for these commodities fluctuate. Such effects can be significant. In order to reduce the impact of fluctuations in 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 attempt to 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, 2009, we had entered into the following swaps:

	Swaps					
	Natural Gas (NYMEX HH)			Oil (NYMEX WTI)		
Remaining Swap Term	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Fair Value (In Thousands)	Barrels Per Day	Weighted Average Hedged Price per Bbl	Fair Value (In Thousands)
Calendar 2010	200	$6.28	$35,454	3,000	$76.06	$(6,786)

Collars

Forest also enters into costless 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, 2009, we had entered into the following collars:

	Collars		
	Oil (NYMEX WTI)		
Collar Term	Barrels Per Day	Weighted Average Hedged Floor and Ceiling Price per Bbl	Fair Value (In Thousands)
Calendar 2010	2,000	$60.00/98.50	$(941)

Basis Swaps

Forest also uses basis swaps in connection with natural gas swaps in order to fix the price differential between the NYMEX Henry Hub price and the index price at which the natural gas production is sold. As of December 31, 2009, we had entered into the following basis swaps:

	Basis Swaps			
Remaining Swap Term	Index	Bbtu Per Day	Weighted Average Hedged Price Differential per MMBtu	Fair Value (In Thousands)
Calendar 2010	Centerpoint	30	$ (.95)	$ (7,576)
Calendar 2010	Houston Ship Channel	50	(.29)	(4,094)
Calendar 2010	Mid Continent	60	(1.04)	(17,705)
Calendar 2010	NGPL TXOK	40	(.44)	(3,741)

The fair value of all our commodity derivative instruments based on various inputs, including published forward prices, at December 31, 2009 was a net liability of approximately $5.4 million.

Interest Rate Risk

Forest periodically enters into interest rate derivative agreements in an attempt to normalize the mix of fixed and floating interest rates within its debt portfolio. As of December 31, 2009, we had entered into the following interest rate swaps:

	Interest Rate Swaps			
Remaining Swap Term	Notional Amount (In Thousands)	Weighted Average Floating Rate	Weighted Average Fixed Rate	Fair Value (In Thousands)
Jan 2010 – Feb 2014	$500,000	1 month LIBOR + 5.89%	8.50%	$(529)
Jan 2010 – May 2014[(1)]	100,000	3 month LIBOR + 5.00%	7.75%	162

(1) Forest voluntarily terminated this interest rate swap subsequent to December 31, 2009 for proceeds of $750,000, including accrued interest.

In addition to the interest rate swaps, during the year ended December 31, 2009, we entered into certain interest rate swaptions, which enable the counterparties to exercise options to enter into interest rate swaps with us in exchange for a premium paid to us. The premiums received on these swaptions are amortized as realized gains on derivatives over the term of the related swaption. We entered into these interest rate swaptions because our targeted floating interest rates were not attainable at that time in the interest rate swap market, yet premiums were available from counterparties for the option to swap Forest's 8.5% fixed rate for the floating rates we had targeted. The table below sets forth our outstanding interest rate swaption as of December 31, 2009.

	Interest Rate Swaption					
Option Term	Swap Term	Premium Received (In Thousands)	Notional Amount (In Thousands)	Floating Rate	Fixed Rate	Fair Value (In Thousands)
Oct 2009 – Jan 2010	Jan 2010 – Feb 2014	$550	$100,000	1 month LIBOR + 5.73%	8.50%	$(229)

Subsequent to December 31, 2009, the interest rate swaption in the table above expired unexercised and we entered into the following interest rate swaption:

	Interest Rate Swaption				
Option Term	Swap Term	Premium Received (In Thousands)	Notional Amount (In Thousands)	Floating Rate	Fixed Rate
Jan 2010 – April 2010	May 2010 – Feb 2014	$350	$100,000	3 month LIBOR + 5.50%	8.50%

The fair value of all our interest rate derivative instruments based on various inputs, including published forward rates, at December 31, 2009 was a net liability of approximately $.6 million.

Derivative Fair Value Reconciliation

The table below sets forth the changes that occurred in the fair values of our open derivative contracts during the year ended December 31, 2009, beginning with the fair value of our derivative contracts on December 31, 2008. 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. It has been our experience that commodity prices are subject to large fluctuations, and we expect this volatility to continue. Actual gains and losses recognized related to our commodity derivative instruments will likely differ from those estimated at December 31, 2009 and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

	Fair Value of Derivative Contracts		
	Commodity	Interest Rate	Total
		(In Thousands)	
As of December 31, 2008	$ 170,111	—	170,111
Premiums received	—	(4,207)	(4,207)
Net increase in fair value	121,708	14,569	136,277
Net contract gains recognized	(297,208)	(10,958)	(308,166)
As of December 31, 2009	$ (5,389)	(596)	(5,985)

Interest Rates on Borrowings

The following table presents principal amounts and related interest rates by year of maturity for Forest's debt obligations at December 31, 2009:

	2010(1)	2011	2013	2014	2019	Total
		(Dollar Amounts in Thousands)				
Long-term debt:						
Fixed rate	$150,000	285,000	112	600,000	1,000,000	2,035,112
Weighted average coupon interest rate	7.75%	8.00%	7.00%	8.50%	7.25%	7.76%
Weighted average effective interest rate(2)	6.56%	7.71%	7.00%	8.50%	7.25%	7.63%

(1) Consists of the 7¾% senior notes due 2014, which Forest irrevocably called in December 2009 and redeemed in January 2010.

(2) The effective interest rate on 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.

Foreign Currency Exchange Rate 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. 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.

Item 8. Financial Statements and Supplementary Data.

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, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. 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 as of December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2009, 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 26, 2010 expressed an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
February 26, 2010

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

	December 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 467,221	2,205
Accounts receivable	126,354	157,226
Derivative instruments	35,643	169,387
Deferred income taxes	7,108	—
Other investments	—	2,327
Inventory	52,211	78,683
Other current assets	41,455	63,221
Total current assets	729,992	473,049
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of $7,511,661 and $5,502,782	1,316,712	3,449,510
Unproved	828,645	964,027
Net oil and gas properties	2,145,357	4,413,537
Other property and equipment, net of accumulated depreciation and amortization of $54,810 and $37,260	113,850	99,627
Net property and equipment	2,259,207	4,513,164
Deferred income taxes	393,061	—
Goodwill	255,908	253,646
Derivative instruments	556	4,608
Other assets	45,966	38,331
	$ 3,684,690	5,282,798
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 284,302	424,941
Accrued interest	25,755	7,143
Derivative instruments	41,358	1,284
Deferred income taxes	—	54,583
Current portion of long-term debt	156,678	—
Asset retirement obligations	4,853	5,852
Other current liabilities	22,074	27,608
Total current liabilities	535,020	521,411
Long-term debt	1,865,836	2,735,661
Asset retirement obligations	88,450	91,139
Derivative instruments	826	2,600
Deferred income taxes	46,884	185,587
Other liabilities	68,520	73,488
Total liabilities	2,605,536	3,609,886
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, none issued and outstanding	—	—
Common stock, 112,337,315 and 97,039,751 shares issued and outstanding	11,234	9,704
Capital surplus	2,652,689	2,354,903
Accumulated deficit	(1,652,426)	(729,293)
Accumulated other comprehensive income	67,657	37,598
Total shareholders' equity	1,079,154	1,672,912
	$ 3,684,690	5,282,798

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands, Except Per Share Amounts)		
Revenues:			
Oil and gas sales	$ 767,830	1,647,171	1,083,081
Interest and other	625	3,589	3,454
Total revenues	768,455	1,650,760	1,086,535
Costs, expenses, and other:			
Lease operating expenses	146,977	167,830	167,473
Production and property taxes	42,903	82,147	55,264
Transportation and processing costs	20,915	19,472	20,200
General and administrative	71,076	74,732	63,751
Depreciation, depletion, and amortization	303,622	532,181	390,338
Accretion of asset retirement obligations	8,311	7,602	6,064
Ceiling test write-down of oil and gas properties	1,575,843	2,369,055	—
Interest expense	163,487	125,679	113,162
Realized and unrealized (gains) losses on derivative instruments, net	(132,148)	(165,529)	41,534
Gain on sale of assets	—	(21,063)	(7,176)
Other, net	1,077	59,655	4,224
Total costs, expenses, and other	2,202,063	3,251,761	854,834
Earnings (loss) before income taxes	(1,433,608)	(1,601,001)	231,701
Income tax:			
Current	70,815	11,139	5,999
Deferred	(581,290)	(585,817)	56,396
Total income tax	(510,475)	(574,678)	62,395
Net earnings (loss)	$ (923,133)	(1,026,323)	169,306
Basic earnings (loss) per common share	$ (8.85)	(11.46)	2.20
Diluted earnings (loss) per common share	$ (8.85)	(11.46)	2.16

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Capital Surplus	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive (Loss) Income	Total Shareholders' Equity
				(In Thousands)		
Balances at January 1, 2007	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 authoritative accounting guidance regarding uncertainty in income taxes (Note 5)	—	—	—	(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
Acquisition of Texas properties	7,250	725	358,875	—	—	359,600
Exercise of stock options	784	78	16,279	—	—	16,357
Employee stock purchase plan	45	5	1,378	—	—	1,383
Restricted stock issued, net of cancellations	684	68	(68)	—	—	—
Amortization of stock-based compensation	—	—	26,770	—	—	26,770
Adoption of authoritative accounting guidance regarding split dollar life insurance (Note 8)	—	—	—	(9,032)	—	(9,032)
Adjustment to pro rata distribution of common stock related to Gulf of Mexico operations spin-off (Note 6)	—	—	(12,385)	—	—	(12,385)
Restricted stock redeemed and other	(102)	(10)	(2,515)	—	—	(2,525)
Comprehensive loss:						
Net loss	—	—	—	(1,026,323)	—	(1,026,323)
Increase in unfunded postretirement benefits, net of tax	—	—	—	—	(8,007)	(8,007)
Foreign currency translation	—	—	—	—	(84,737)	(84,737)
Total comprehensive loss						(1,119,067)
Balances at December 31, 2008	97,040	9,704	2,354,903	(729,293)	37,598	1,672,912
Common stock issued, net of offering costs	14,375	1,438	254,779	—	—	256,217
Exercise of stock options	171	17	3,049	—	—	3,066
Employee stock purchase plan	123	12	1,499	—	—	1,511
Restricted stock issued, net of cancellations	657	66	(66)	—	—	—
Amortization of stock-based compensation	—	—	26,820	—	—	26,820
Tax benefit of employee stock option exercises	—	—	12,253	—	—	12,253
Restricted stock redeemed and other	(29)	(3)	(548)	—	—	(551)
Comprehensive loss:						
Net loss	—	—	—	(923,133)	—	(923,133)
Decrease in unfunded postretirement benefits, net of tax	—	—	—	—	2,152	2,152
Foreign currency translation	—	—	—	—	27,907	27,907
Total comprehensive loss						(893,074)
Balances at December 31, 2009	112,337	$11,234	2,652,689	(1,652,426)	67,657	1,079,154

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
Operating activities:			
Net earnings (loss)	$ (923,133)	(1,026,323)	169,306
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	303,622	532,181	390,338
Unrealized losses (gains) on derivative instruments, net	176,018	(221,490)	117,499
Deferred income tax	(581,290)	(585,817)	56,396
Ceiling test write-down of oil and gas properties	1,575,843	2,369,055	—
Stock-based compensation expense	16,779	17,171	10,895
Accretion of asset retirement obligations	8,311	7,602	6,064
Gain on sale of assets	—	(21,063)	(7,176)
Unrealized foreign currency exchange (gain) loss	(17,974)	19,481	(7,694)
Unrealized losses on other investments, net	2,327	34,042	4,948
Other, net	5,773	(2,549)	1,402
Changes in operating assets and liabilities, net of effects of acquisitions and divestitures:			
Accounts receivable	35,790	42,854	353
Other current assets	30,809	(80,214)	1,557
Accounts payable and accrued liabilities	(47,956)	15,796	(9,592)
Accrued interest and other current liabilities	12,077	(30,686)	(26,051)
Net cash provided by operating activities	596,996	1,070,040	708,245
Investing activities:			
Capital expenditures for property and equipment:			
Exploration, development, and other acquisition costs	(637,831)	(2,338,488)	(787,735)
Other fixed assets	(30,887)	(66,005)	(32,169)
Proceeds from sales of assets	1,054,062	309,940	502,048
Acquisition of Houston Exploration, net of cash acquired (Note 2)	—	—	(775,365)
Other, net	28	1,060	—
Net cash provided (used) by investing activities	385,372	(2,093,493)	(1,093,221)
Financing activities:			
Proceeds from bank borrowings	868,533	3,203,360	1,536,526
Repayments of bank borrowings	(2,173,687)	(2,195,101)	(1,542,063)
Issuance of senior notes, net of issuance costs	559,767	247,188	739,176
Redemption of 8% senior notes	—	(265,000)	—
Repurchases of 7% senior subordinated notes	(970)	(4,710)	—
Repayments of Alaska Credit Agreements	—	—	(375,000)
Proceeds from common stock offering, net of offering costs	256,217	—	—
Tax benefit of employee stock option exercises	12,253	—	—
Proceeds from the exercise of options and from employee stock purchase plan	4,577	17,740	12,845
Change in bank overdrafts	(39,411)	21,012	5,288
Other, net	(4,143)	(8,231)	(17,220)
Net cash (used) provided by financing activities	(516,864)	1,016,258	359,552
Effect of exchange rate changes on cash	(488)	(285)	1,945
Net increase (decrease) in cash and cash equivalents	465,016	(7,480)	(23,479)
Cash and cash equivalents at beginning of year	2,205	9,685	33,164
Cash and cash equivalents at end of year	$ 467,221	2,205	9,685
Cash paid during the year for:			
Interest	$ 148,242	141,993	125,276
Income taxes	4,302	2,530	6,445

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2009, 2008, and 2007

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Description of the Business

Forest Oil Corporation ("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. Forest 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 two other foreign countries.

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of Forest Oil Corporation and its wholly-owned consolidated subsidiaries (collectively, "Forest" or the "Company"). Certain amounts in prior years' financial statements have been reclassified to conform to the 2009 financial statement presentation due primarily to changing to an unclassified statement of operations.

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, revenues, 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, determining impairments of investments in unproved properties, valuing deferred tax assets and goodwill, and estimating fair values of financial instruments, including derivative instruments.

Cash Equivalents

The Company considers all highly liquid investments with original maturities of three months or less and all money market funds with no restrictions on the Company's ability to withdraw money from the funds to be cash equivalents.

Property and Equipment

In January 2010, the Financial Accounting Standards Board ("FASB") issued oil and gas reserve estimation and disclosure authoritative accounting guidance effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the Securities and Exchange Commission's ("SEC") final rule, "Modernization of Oil and Gas Reporting", which was also effective for annual reports for fiscal years ending on or after December 31, 2009. The new FASB guidance and SEC rule include changes to pricing used to estimate oil and gas reserves, broaden the types of technologies that a company may use to establish oil and gas reserves estimates, and broaden the definition of oil and gas producing activities to include the extraction of non-traditional resources, including bitumen extracted from oil sands as well as oil and gas extracted from shales. Accordingly, the Company adopted both the FASB's new authoritative accounting guidance and the SEC's new rule as of December 31, 2009.

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 the periods presented, the Company's primary oil and gas operations were conducted in the United States and Canada. All costs incurred in the acquisition, exploration, and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) and the fair value of estimated future costs of site restoration, dismantlement, and abandonment activities are capitalized. For the years ended December 31, 2009, 2008, and 2007, Forest capitalized \$47.0 million, \$47.3 million, and \$43.6 million of general and administrative costs (including stock-based compensation), respectively. Interest costs related to significant unproved properties that are under development are also capitalized to oil and gas properties. During 2009, 2008, and 2007, the Company capitalized \$12.2 million, \$17.9 million, and \$13.9 million, respectively, of interest costs attributed to unproved properties.

Investments in unproved properties, including capitalized interest costs, 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, geographic and geologic data obtained relating to the properties, and estimated discounted future net cash flows from the properties. Estimated discounted future net cash flows are based on discounted future net revenues associated with probable and possible reserves, risk adjusted as appropriate. 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.

The Company performs a ceiling test each quarter on a country-by-country basis. The full cost ceiling test is a limitation on capitalized costs prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is not a fair value based measurement. Rather, it is a standardized mathematical calculation. 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, a ceiling test write-down would be recognized to the extent of the excess capitalized costs. The December 31, 2009 ceiling test was based on average prices during the twelve-month period prior to December 31, 2009 pursuant to the SEC's new "Modernization of Oil and Gas Reporting" rule and did not result in a write-down. The March 31, 2009 ceiling test, which was based on the March 31, 2009 spot prices, resulted in non-cash write-downs of oil and gas property costs of \$1.4 billion in the United States cost center and \$199.0 million in the Canada cost center. The December 31, 2008 ceiling test, which was based on the December 31, 2008 spot prices, resulted in a non-cash write-down of oil and gas property costs of \$2.4 billion in the United States cost center.

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. The Company has historically updated its quarterly depletion calculations with its quarter-end reserves estimates. Based on this accounting policy, the December 31, 2009 reserves estimates were used for the Company's fourth quarter 2009 depletion calculation.

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 fifteen years.

Asset Retirement Obligations

Forest records 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 activity for the Company's asset retirement obligations for the periods indicated:

	Year Ended December 31,	
	2009	2008
	(In Thousands)	
Asset retirement obligations at beginning of period	$ 96,991	90,505
Accretion expense	8,311	7,602
Liabilities incurred	4,976	10,375
Liabilities settled	(3,352)	(5,867)
Disposition of properties	(13,334)	(7,262)
Liabilities assumed	—	2,747
Revisions of estimated liabilities	(2,089)	1,836
Impact of foreign currency exchange rate	1,800	(2,945)
Asset retirement obligations at end of period	93,303	96,991
Less: current asset retirement obligations	(4,853)	(5,852)
Long-term asset retirement obligations	$ 88,450	91,139

Oil and Gas Sales

The Company recognizes revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred, (iii) the seller's price to the buyer is fixed or determinable and (iv) collectibility is reasonably assured.

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

When the Company has an interest with other producers in properties from which natural gas is produced, the Company uses the entitlements method to account for any imbalances. Imbalances occur when the Company sells more or less product than it is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that the Company sells in excess of its entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount the Company sells is recognized as revenue and a receivable is accrued. At December 31, 2009 and 2008, the Company had gas imbalance payables of $9.9 million and $9.8 million, respectively, and gas imbalance receivables of $7.2 million and $8.1 million, respectively.

In 2009, sales to one purchaser were approximately 14% of the Company's total revenues. In 2008, sales to two purchasers were approximately 13% and 12%, respectively, of the Company's total revenues. In 2007, there were no individual purchasers who accounted for 10% or more of the Company's total revenues.

Accounts Receivable

The components of accounts receivable include the following:

	December 31,	
	2009	2008
	(In Thousands)	
Oil and gas sales	$ 71,131	94,911
Joint interest billings	33,754	46,357
Other	22,937	16,376
Allowance for doubtful accounts	(1,468)	(418)
Total accounts receivable	$126,354	157,226

Forest's accounts receivable are primarily from purchasers of the Company's oil and natural gas production and from other exploration and production companies which own working interests in the properties that the Company operates. This industry concentration could adversely impact Forest's overall credit risk, because the Company's customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices, and other conditions. Forest's oil and gas production is sold to various purchasers in accordance with the Company's credit policies and procedures. These policies and procedures take into account, among other things, the creditworthiness of potential purchasers and concentrations of credit risk. Forest generally requires letters of credit or parental guarantees for receivables from parties that are deemed to have sub-standard credit or other financial concerns, unless the Company can otherwise mitigate the perceived credit exposure. Forest believes that the loss of one or more of the Company's current oil and gas purchasers would not have a material adverse effect on the Company's ability to sell its production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption.

Income Taxes

The Company recognizes 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.

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 translated at end-of-period exchange rates, and related translation adjustments other than those related to intercompany debt are reported as a component of shareholders' equity in accumulated other comprehensive income. Statement of operations accounts are translated at the average of the exchange rates for the period.

During 2009, 2008, and 2007, Forest realized approximately $(.1) million, $1.0 million, and $(7.7) million, respectively, of foreign currency exchange (gains) losses in connection with the repayment of intercompany debt owed to Forest Oil Corporation by Canadian Forest. During 2009, 2008, and 2007, Forest recorded approximately $(18.0) million, $19.5 million, and $(7.7) million, respectively, of unrealized losses (gains) related to the intercompany debt with Canadian Forest since the debt is denominated in U.S. dollars.

Earnings (Loss) per Share

Basic earnings (loss) per share is computed by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. Under the treasury stock method, diluted earnings (loss) per share is computed by dividing net earnings (loss) adjusted for the effects of certain contracts that provide the issuer or holder with a choice between settlement methods by the weighted average number of common shares outstanding adjusted for the dilutive effect, if any, of potential common shares (i.e. stock options, unvested restricted stock grants, and unvested phantom stock units that may be settled in shares). No potential common shares shall be included in the computation of any diluted per share amount when a net loss exists.

The two-class method of computing earnings per share is required for those entities that have participating securities or multiple classes of common stock. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. In June 2008, the FASB issued authoritative guidance that addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method. This guidance was effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, Forest adopted this guidance as of January 1, 2009. All prior period earnings per share data presented have been adjusted retrospectively to conform to the provisions of this guidance.

Restricted stock issued under Forest's stock incentive plans has the right to receive non-forfeitable cash dividends, participating on an equal basis with common stock. Phantom stock units issued to directors under Forest's stock incentive plans also have the right to receive non-forfeitable cash dividends, participating on an equal basis with common stock, while phantom stock units issued to employees do not participate in dividends. Stock options issued under Forest's stock incentive plans do not participate in dividends. Therefore, restricted stock issued to employees and directors and phantom stock units issued to directors are participating securities and earnings must now be allocated to both common stock and these participating securities under the two-class method. However, these participating securities do not have a contractual obligation to share in Forest's losses. Therefore, in periods of net loss, none of the loss is allocated to these participating securities, consequently, the adoption of this guidance will have no impact on Forest's basic earnings per share for those periods. In periods of net earnings, however, both basic and diluted earnings per share calculated under the two-class method will likely be lower than they would have been prior to the adoption of this guidance.

Stock options, unvested restricted stock grants, and unvested phantom stock units that may be settled in shares were not included in the calculation of diluted loss per share for the years ended December 31, 2009 and 2008 as their inclusion would have an antidilutive effect. Unvested restricted stock grants were not included in the calculation of diluted earnings per share for the year ended December 31, 2007 as their inclusion would have an antidilutive effect.

The following sets forth the calculation of basic and diluted earnings (loss) per share for the periods presented.

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands, Except Per Share Amounts)		
Net earnings (loss)	$(923,133)	(1,026,323)	169,306
Net earnings attributable to participating securities	—	—	(2,140)
Net earnings (loss) attributable to common stock for basic earnings per share	(923,133)	(1,026,323)	167,166
Adjustment for liability-classified stock-based compensation awards	—	—	210
Adjustment to net earnings attributable to participating securities	—	—	(3)
Net earnings (loss) for diluted earnings per share	$(923,133)	(1,026,323)	167,373
Weighted average common shares outstanding during the period	104,336	89,591	76,101
Dilutive effects of potential common shares	—	—	1,225
Weighted average common shares outstanding during the period, including the effects of dilutive potential common shares	104,336	89,591	77,326
Basic earnings (loss) per common share	$ (8.85)	(11.46)	2.20
Diluted earnings (loss) per common share	$ (8.85)	(11.46)	2.16

Stock-Based Compensation

Compensation cost is measured at the grant date based on the fair value of the awards (stock options, restricted stock, employee stock purchase plan rights) or is measured at the reporting date based on the current stock price (phantom stock units), and is recognized on a straight-line basis over the requisite service period (usually the vesting period).

Derivative Instruments

The Company records all derivative instruments as either assets or liabilities at fair value. The Company may or may not elect to designate a derivative instrument as a hedge against changes in the fair value of an asset or a liability (a "fair value hedge") or against exposure to variability in expected future cash flows (a "cash flow hedge"). The Company has not elected to designate its derivative instruments as hedges and, therefore, records all changes in fair value of its derivative instruments through earnings.

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

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, 2009 and 2008 totaled $31.2 million and $23.5 million, respectively, and are being amortized over the life of the respective debt instruments. The increase in 2009 includes the debt issue costs associated with the February 2009 issuance of the $600 million 8½% senior notes due 2014.

Inventory

Inventories were comprised of $52.2 million and $78.7 million of materials and supplies as of December 31, 2009 and 2008, respectively. The Company's materials and supplies inventory, which is acquired for use in future drilling operations, is primarily comprised of items such as tubing and casing.

Goodwill

The Company is required to make an annual impairment assessment in lieu of periodic amortization. The Company performs its annual goodwill impairment test in the second quarter of the year. In addition, the Company tests goodwill for impairment if events or circumstances change between annual tests indicating a possible impairment. 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, or depressed oil and natural gas prices could lead to an impairment of goodwill in future periods. The Company had no goodwill impairments for the years ended December 31, 2009, 2008, and 2007.

A portion of Forest's goodwill is assigned to the Canadian geographical business segment, and normal fluctuations in the balance will occur between periods based upon changes in foreign currency exchange rates. Forest recognized $168.0 million of goodwill associated with the Houston Exploration acquisition, which occurred in June 2007, 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 and changes in the unfunded postretirement benefits.

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

The components of accumulated other comprehensive earnings (loss) for the years ended December 31, 2009, 2008, and 2007 are as follows:

	Foreign Currency Translation	Unfunded Postretirement Benefits[1]	Accumulated Other Comprehensive Income (Loss)
		(In Thousands)	
Balance at January 1, 2007	$ 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
2008 activity	(84,737)	(8,007)	(92,744)
Balance at December 31, 2008	50,607	(13,009)	37,598
2009 activity	27,907	2,152	30,059
Balance at December 31, 2009	$ 78,514	(10,857)	67,657

(1) Net of tax.

Impact of Recently Issued Accounting Pronouncements

In January 2010, the FASB issued Accounting Standards Update ("ASU") No. 2010-06, "Improving Disclosures about Fair Value Measurements." This ASU amends existing authoritative guidance to require additional disclosures regarding fair value measurements, including the amounts and reasons for significant transfers between Level 1 and Level 2 of the fair value hierarchy, the reasons for any transfers into or out of Level 3 of the fair value hierarchy, and presentation, on a gross basis, of information regarding purchases, sales, issuances, and settlements within the Level 3 rollforward. This ASU also clarifies certain existing disclosure requirements. The guidance within this ASU is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements within the Level 3 rollforward, which are effective for interim and annual reporting periods beginning after December 15, 2010. The adoption of this authoritative guidance will have no impact on the Company's financial position or results of operations, but may require expanded disclosure about fair value measurements.

(2) ACQUISITIONS AND DIVESTITURES:

Acquisitions

Texas Properties Acquisition

On September 30, 2008, Forest acquired producing oil and natural gas properties located in its Greater Buffalo Wallow and East Texas / North Louisiana core areas from Cordillera Texas, L.P. Forest paid approximately $570 million in cash and issued 7.25 million shares of Forest's common stock, valued at approximately $360 million (based on a September 30, 2008 closing price), to the seller for the acquired assets.

East Texas / North Louisiana Properties Acquisition

On May 2, 2008, Forest acquired producing oil and natural gas properties located in its core East Texas / North Louisiana area. Forest paid approximately $284 million for the assets.

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. Pursuant to the terms and conditions of the agreement and plan of merger, Forest paid total merger consideration of $750 million in cash and issued approximately 24 million common shares, valued at $30.28 per share. 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 final allocation of the total purchase price of Houston Exploration to the acquired assets and liabilities of Houston Exploration. The allocation represents the estimated fair values assigned to each of the assets acquired and liabilities assumed.

	(In Thousands)
Fair value of Houston Exploration's net assets:	
Net working capital, including cash of $3.5 million	$ (809)
Proved oil and gas properties	1,741,823
Unproved oil and gas properties	448,100
Goodwill	168,043
Other assets	14,537
Derivative instruments	(45,170)
Long-term debt	(182,532)
Asset retirement obligations	(36,424)
Deferred income taxes	(584,049)
Other liabilities	(18,210)
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 $168.0 million was 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.

(2) **ACQUISITIONS AND DIVESTITURES: (Continued)**

The following summary pro forma combined statement of operations data of Forest for the year ended December 31, 2007 has been prepared to give effect to the merger as if the merger had occurred on January 1, 2007. 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 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.

	Year Ended December 31, 2007
	(In Thousands, Except Per Share Amounts)
Revenues	$1,304,849
Earnings from continuing operations	181,591
Net earnings	181,591
Basic earnings per common share:	
From continuing operations	$ 2.07
Basic earnings per common share	2.07
Diluted earnings per common share:	
From continuing operations	$ 2.04
Diluted earnings per common share	2.04

Divestitures

Permian Basin Divestitures

During 2009, Forest sold all of its oil and natural gas properties located in the Permian Basin in West Texas and New Mexico for approximately $908.3 million in cash.

Miscellaneous Divestitures

During the year ended December 31, 2009, Forest sold various non-core U.S. and Canadian oil and natural gas properties for total proceeds of $145.6 million.

During the year ended December 31, 2008, Forest sold various non-core U.S. and international oil and natural gas properties for total proceeds of $309.9 million. These divestitures included the sale of the majority of Forest's oil and natural gas properties in the Rocky Mountains and all of Forest's oil and natural gas properties in Gabon. The Gabon sale, for net proceeds of $23.9 million, resulted in a gain on the sale of $21.1 million in the third quarter.

During the year ended December 31, 2007, Forest sold various properties 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 is being amortized over the term of the lease.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

Sale of Alaska Assets

In addition to the miscellaneous divestitures discussed above, 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 (the "PERL Shares"), and a zero coupon senior subordinated note from PERL due 2014 in the principal amount at stated maturity of $60.8 million (the "PERL Note"). A portion of the cash consideration, $269 million, was applied to prepay all amounts due under the Alaska credit agreements, including accrued interest and prepayment premiums. See Note 9 to the Consolidated Financial Statements for more information on the fair values of the PERL Shares and PERL Note.

(3) PROPERTY AND EQUIPMENT:

Net property and equipment consists of the following for the periods indicated:

	December 31,	
	2009	2008
	(In Thousands)	
Oil and gas properties:		
Proved	$ 8,828,373	8,952,292
Unproved	828,645	964,027
Accumulated depletion	(7,511,661)	(5,502,782)
Net oil and gas properties	2,145,357	4,413,537
Other property and equipment:		
Furniture and fixtures, computer hardware and software, and other equipment	168,660	136,887
Accumulated depreciation and amortization	(54,810)	(37,260)
Net other property and equipment	113,850	99,627
Total net property and equipment	$ 2,259,207	4,513,164

The following table sets forth a summary of Forest's investment in unproved properties as of December 31, 2009, by the year in which such costs were incurred:

	Total	2009	2008	2007	2006 and Prior
			(In Thousands)		
United States:					
Acquisition costs	$575,645	—	441,201	111,598	22,846
Exploration costs	129,632	67,277	49,617	4,885	7,853
Total United States	705,277	67,277	490,818	116,483	30,699
Canada:					
Acquisition costs	5,171	—	—	—	5,171
Exploration costs	61,036	18,871	31,478	7,016	3,671
Total Canada	66,207	18,871	31,478	7,016	8,842
International:					
Acquisition costs	740	—	—	—	740
Exploration costs	56,421	1,451	2,360	900	51,710
Total International	57,161	1,451	2,360	900	52,450
Total	$828,645	87,599	524,656	124,399	91,991

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

(3) PROPERTY AND EQUIPMENT: (Continued)

work-in-progress on various projects. The Company expects that substantially all of its unproved property costs in the U.S. and Canada as of December 31, 2009 will be reclassified to proved properties within ten years. Forest's exploration project in South Africa accounts for all of the international costs not being amortized as of December 31, 2009. The Company continues to pursue commercial development of the Ibhubesi field discovery in South Africa including continued efforts toward securing gas contracts for the Ibhubesi field.

(4) DEBT:

The components of debt are as follows:

	December 31, 2009				December 31, 2008			
	Principal	Unamortized Premium (Discount)	Other[5]	Total	Principal	Unamortized Premium (Discount)	Other[5]	Total
				(In Thousands)				
U.S. Credit Facility[1]	$ —	—	—	—	1,190,000	—	—	1,190,000
Canadian Credit Facility[1]	—	—	—	—	94,415	—	—	94,415
8% Senior Notes due 2011	285,000	2,583	1,638	289,221	285,000	3,875	2,475	291,350
7% Senior Subordinated Notes due 2013[2]	112	(2)	—	110	1,112	(25)	—	1,087
8½% Senior Notes due 2014[3]	600,000	(24,029)	—	575,971	—	—	—	—
7¾% Senior Notes due 2014[4]	150,000	(1,035)	7,713	156,678	150,000	(1,273)	9,492	158,219
7¼% Senior Notes due 2019	1,000,000	534	—	1,000,534	1,000,000	590	—	1,000,590
Total debt	2,035,112	(21,949)	9,351	2,022,514	2,720,527	3,167	11,967	2,735,661
Less: current portion of long-term debt[4]	(150,000)	1,035	(7,713)	(156,678)	—	—	—	—
Long-term debt	$1,885,112	(20,914)	1,638	1,865,836	2,720,527	3,167	11,967	2,735,661

(1) In December 2009, the Company repaid all amounts outstanding under its credit facilities.

(2) In June 2009, the Company repurchased $1.0 million in principal amount of 7% senior subordinated notes due 2013 at 97% of par value.

(3) In February 2009, the Company issued $600 million in principal amount of 8½% senior notes due 2014 at 95.15% of par for proceeds of $559.8 million (net of related initial purchaser discounts) and used the net proceeds to pay down outstanding balances on the Company's U.S. credit facility.

(4) In December 2009, the Company irrevocably called the 7¾% senior notes due 2014 and redeemed these notes in January 2010 at 101.292% of par.

(5) 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

As of December 31, 2009, the Company had syndicated bank revolving credit agreements with total lender commitments of $1.8 billion. The credit agreements consisted of a $1.65 billion U.S. credit facility through a syndicate of banks led by JPMorgan Chase Bank, N.A. (the "U.S. Credit Facility") and a $150 million Canadian credit facility through a syndicate of banks led by JPMorgan Chase Bank, N.A., Toronto Branch (the "Canadian Credit Facility," and together with the U.S. Credit Facility, the "Credit Facilities"). The Credit Facilities will mature in June 2012. Forest's availability under the Credit Facilities is governed by a borrowing base (the "Global Borrowing Base"). The determination of the Global Borrowing Base is made by the lenders in their sole discretion, on a semi-annual basis, taking into consideration the estimated value of Forest's oil and gas properties based on pricing models determined by the lenders at such time, in accordance with the lenders' customary practices for oil and gas loans. The available borrowing amount under the Credit Facilities could increase or decrease based on such redetermination. The next redetermination of the borrowing base is expected to occur in the second quarter of 2010. In addition to the semi-annual redeterminations, Forest and the lenders each have discretion at any time, but not more often than once during a calendar year, to have the Global Borrowing Base redetermined.

The Global Borrowing Base is also subject to change in the event (i) the Company issues senior notes, in which case the Global Borrowing Base will immediately be reduced by an amount equal to $0.30 for every $1.00 principal amount of any newly issued senior notes, excluding any senior notes that the Company may issue to refinance senior notes that were outstanding on May 9, 2008 or (ii) if the Company sells oil and natural gas properties included in the Global Borrowing Base having a fair market value in excess of 10% of the Global Borrowing Base then in effect. The Global Borrowing Base is subject to other automatic adjustments under the facilities. As a result of issuing $600 million of 8½% senior notes due 2014 in February 2009, Forest's borrowing base was lowered from $1.8 billion to $1.62 billion effective February 17, 2009 and as a result of the Permian Basin asset divestiture in December 2009, Forest's borrowing base was lowered from $1.62 billion to $1.3 billion effective December 21, 2009. As a result of the December adjustment, the Company reallocated amounts under the U.S. Credit Facility and Canadian Credit Facility and currently has allocated $1.155 billion to the U.S. Credit Facility and $145 million to the Canadian Credit Facility. A lowering of the Global Borrowing Base could require the Company to repay indebtedness in excess of the Global Borrowing Base in order to cover the deficiency. The automatic lowering of the Global Borrowing Base on February 17, 2009 and again on December 21, 2009 did not result in any deficiency, and therefore the Company did not have to repay any amounts.

Borrowings under the U.S. Credit Facility bear interest at one of two rates as may be elected by Forest. Loans will bear interest at a rate that is based on interest rates applicable to dollar deposits in the London interbank market ("LIBO Rate"), or a rate based on the greater of the prime rate announced by the global administrative agent or the federal funds rate plus ½ of 1%. Loans under the Canadian Credit Facility will bear interest at a rate that may be based on the base rate announced by the Canadian administrative agent, the LIBO Rate, a rate based on the greater of the rate for U.S. dollar denominated loans made by the Canadian administrative agent and the federal funds rate plus ½ of 1%, or a banker's acceptance rate.

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 also include financial covenants. If the Company were to fail to perform its obligations under these covenants or other covenants and obligations, it could cause an event of default and the Credit Facilities could be terminated and amounts outstanding could be declared immediately due and payable by the lenders, subject to notice and cure periods in certain cases. Such events of default include non-payment, breach of warranty, non-performance of 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 Credit Facility. In addition, 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. An acceleration of the Company's indebtedness under the Credit Facilities could in turn result in an event of default under the indentures for the Company's senior notes, which in turn could result in the acceleration of the senior notes. Likewise, a default under our indebtedness other than the Credit Facilities, such as the indentures under our senior notes, in turn could result in an event of default under our Credit Facilities, which in turn could result in the acceleration of the obligations under the Credit Facilities

(4) DEBT: (Continued)

Under the Credit Facilities, the Company is required to mortgage and grant a security interest in the greater of 75% of the present value of the Company's consolidated proved oil and gas properties, or 1.875 multiplied by the allocated U.S. borrowing base. The Company also has pledged the stock of several subsidiaries to the lenders to secure the Credit Facilities. Under certain circumstances, the Company could be obligated to pledge additional assets as collateral. If Forest's corporate credit ratings assigned 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. In addition to these collateral requirements, one of the Company's subsidiaries, Forest Oil Permian Corporation, is a subsidiary guarantor of the Credit Facilities.

Of the $1.8 billion total commitments under the Credit Facilities, JPMorgan and seven other banks hold approximately 62% of the total commitments, with each of these eight lenders holding an equal share. With respect to the other 38% of the total commitments, no single lender holds more than 4.6% of the total commitments.

At December 31, 2009, there were no outstanding borrowings under the Credit Facilities.

8½% Senior Notes Due 2014

On February 17, 2009, Forest issued $600 million in principal amount of 8½% senior notes due 2014 (the "8½% Notes") at 95.15% of par for net proceeds of $559.8 million, after deducting initial purchaser discounts. Proceeds from the 8½% Notes were used to pay down outstanding balances on the Company's U.S. Credit Facility. Forest may redeem up to 35% of the 8½% Notes at any time prior to February 15, 2012, on one or more occasions, with the proceeds from certain equity offerings at a redemption price equal to 108.5% of the principal amount, plus accrued but unpaid interest. The 8½% Notes 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.

7¼% Senior Notes Due 2019

On May 22, 2008, Forest issued an additional $250 million in principal amount of 7¼% senior notes due 2019 (the "7¼% Notes") at 100.25% of par for net proceeds of $247.2 million, after deducting initial purchaser discounts. The additional 7¼% Notes were used to redeem a portion of the Company's 8% senior notes due 2008 that matured on June 15, 2008. The additional 7¼% Notes were issued under an existing indenture (the "Indenture") dated as of June 6, 2007. Forest previously issued an aggregate principal amount of $750 million in 7¼% Notes under the Indenture, and there is now a total of $1 billion in 7¼% Notes outstanding.

(4) **DEBT: (Continued)**

Forest 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. Forest 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:

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

Forest may also redeem the 7¼% Notes, in whole or in part, at a price equal to the principal amount plus a "make whole" premium, at any time prior to June 15, 2012, using a discount rate of the Treasury rate plus 0.50%, plus accrued but unpaid interest.

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.

7¾% Senior Notes Due 2014

In December 2009, Forest notified the trustee and note holders of the 7¾% senior notes due 2014 (the "7¾% Notes") that it was calling the 7¾% Notes. This notice was irrevocable after it was given. The 7¾% Notes were redeemed in January 2010 at 101.292% of par and a net gain of $4.6 million was recognized in January 2010 upon redemption. Forest utilized a portion of the sales proceeds received from the December 2009 Permian Basin divestiture to fund the redemption.

Alaska Credit Agreements

On December 8, 2006, Forest, through its wholly-owned subsidiaries, Forest Alaska Operating LLC and Forest Alaska Holding LLC, issued, on a non-recourse basis to Forest, term loan financing facilities in the aggregate principal amount of $375 million (the "Alaska Credit Agreements"). During the year ended December 31, 2007, Forest repaid the Alaska Credit Agreements in full, recognizing associated debt extinguishment costs of $12.2 million.

(4) DEBT: (Continued)

Principal Maturities

Principal maturities of the Company's debt at December 31, 2009 are as follows (in thousands):

	Principal Maturities
2010	$ 150,000
2011	285,000
2012	—
2013	112
2014	600,000
Thereafter	1,000,000

(5) INCOME TAXES:

Income Tax Provision

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

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
Current:			
Federal	$ 62,366	3,979	3,503
Foreign	—	3,381	(1,798)
State	8,449	3,779	4,294
	70,815	11,139	5,999
Deferred:			
Federal	(520,320)	(590,078)	58,536
Foreign	(49,293)	23,312	(2,098)
State, net	(11,677)	(19,051)	(42)
	(581,290)	(585,817)	56,396
	$(510,475)	(574,678)	62,395

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

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
United States Federal	$(1,245,387)	(1,673,671)	177,999
Foreign	(188,221)	72,670	53,702
	$(1,433,608)	(1,601,001)	231,701

(5) INCOME TAXES: (Continued)

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

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
Federal income tax at 35% of income before income taxes and discontinued operations	$(501,763)	(560,364)	81,095
State income taxes, net of federal income tax benefits	(13,913)	(18,895)	2,960
Change in the valuation allowance for deferred tax assets	(10,011)	1,956	(1,831)
Effect of differing tax rates in Canada	11,249	(3,971)	(1,517)
Effect of Canadian statutory rate reductions	—	—	(16,815)
Effect of state statutory rate reductions	—	(1,940)	(2,397)
Effect of federal, state, and foreign tax on permanent differences	555	7,353	277
Other	3,408	1,183	623
Total income tax	$(510,475)	(574,678)	62,395

Net Deferred Tax Assets and Liabilities

The components of the net deferred tax assets and liabilities by geographical segment at December 31, 2009 and 2008 are as follows:

	December 31, 2009		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Property and equipment	$290,636	—	290,636
Unrealized gains on derivative contracts, net	2,129	—	2,129
Allowance for doubtful accounts	451	—	451
Investment in PERL common stock and Note	15,240	—	15,240
Accrual for post retirement benefits	7,148	303	7,451
Stock-based compensation accruals	16,673	315	16,988
Net operating loss carryforwards	13,313	—	13,313
Capital loss carryforward	—	2,618	2,618
Alternative minimum tax credit carryforward	47,260	—	47,260
Other	9,345	1,278	10,623
Total gross deferred tax assets	402,195	4,514	406,709
Less valuation allowance	(2,026)	(1,141)	(3,167)
Net deferred tax assets	400,169	3,373	403,542
Deferred tax liabilities:			
Property and equipment	—	(48,388)	(48,388)
Other	—	(1,869)	(1,869)
Total gross deferred tax liabilities	—	(50,257)	(50,257)
Net deferred tax assets (liabilities)	$400,169	(46,884)	353,285

(5) INCOME TAXES: (Continued)

	December 31, 2008		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Allowance for doubtful accounts	$ 441	—	441
Investment in PERL common stock and Note	14,536	—	14,536
Accrual for post retirement benefits	7,903	261	8,164
Stock-based compensation accruals	9,071	227	9,298
Net operating loss carryforwards	47,446	—	47,446
Capital loss carryforward	—	2,408	2,408
Depletion carryforward	7,301	—	7,301
Alternative minimum tax credit carryforward	34,093	—	34,093
Other	10,875	1,265	12,140
Total gross deferred tax assets	131,666	4,161	135,827
Less valuation allowance	(10,942)	(2,767)	(13,709)
Net deferred tax assets	120,724	1,394	122,118
Deferred tax liabilities:			
Property and equipment	(207,215)	(93,614)	(300,829)
Unrealized gains on derivative contracts, net	(61,459)	—	(61,459)
Total gross deferred tax liabilities	(268,674)	(93,614)	(362,288)
Net deferred tax liabilities	$(147,950)	(92,220)	(240,170)

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

	December 31, 2009		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax assets	$ 7,108	—	7,108
Non-current deferred tax assets (liabilities)	393,061	(46,884)	346,177
Net deferred tax assets (liabilities)	$400,169	(46,884)	353,285

	December 31, 2008		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax liabilities	$ (54,583)	—	(54,583)
Non-current deferred tax liabilities	(93,367)	(92,220)	(185,587)
Net deferred tax liabilities	$(147,950)	(92,220)	(240,170)

Valuation Allowances

The decrease in the valuation allowance for 2009 of $10.0 million primarily relates to tax loss carryforwards of an acquired subsidiary utilized in the current year. The change in the valuation allowance for 2008 and 2007 of $2.0 million and $1.8 million, respectively, relates to adjustments to Canadian tax loss carryforwards.

(5) INCOME TAXES: (Continued)

The Company has a net deferred tax asset of $1.4 million in international locations. The Company has, in prior years, established a valuation allowance equal to the $1.4 million net deferred tax asset as the Company currently does not have production in the related international locations.

Tax Attributes

Net Operating Losses

U.S. federal net operating loss carryforwards ("NOLs") at December 31, 2009 were approximately $38.0 million, with $5.8 million and $32.2 million scheduled to expire in 2010 and 2019, respectively. In the current year, $120.7 million of NOLs and $20.5 million of depletion carryforwards were used to reduce current tax expense. In addition, $34.4 million of federal net operating loss carryforwards relating to the tax benefit associated with stock compensation gave rise to a financial benefit as a reduction in current tax expense in accordance with authoritative accounting guidance regarding stock-based compensation. The tax effect was recognized as an increase in capital surplus.

The statute of limitations is closed for the Company's U.S. federal income tax returns for years ending on or before December 31, 2005. Pre-acquisition returns of acquired businesses are also closed for tax years ending on or before December 31, 2005. However, the Company has utilized, and will continue to utilize, NOLs (including NOLs of acquired businesses) in its open tax years. The earliest available NOLs were generated in the tax year beginning January 1, 1999, 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, 1995. The Company's most recent Canadian income tax return that is closed to potential audit adjustments is the tax year ended December 31, 2004.

Alternative Minimum Tax Credits

The Alternative Minimum Tax ("AMT") credit carryforward available to reduce future U.S. federal regular taxes equaled an aggregate amount of $47.3 million at December 31, 2009, which can be carried forward indefinitely.

Undistributed Earnings from Canadian Operations

The Company's Canadian operations generated a book loss (after tax) of approximately $138.9 million ($177.7 million CDN) during 2009. As of December 31, 2009, the Company's Canadian operations had reported accumulated undistributed book earnings of approximately $49.7 million ($63.6 CDN). 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 2009, all cash flow generated in Canada was reinvested in Canadian capital expenditures. Based on its current plans, the Company intends that future cash flows generated by Canadian operations will continue to be reinvested in Canadian exploration, development, or acquisition activities or utilized to satisfy external and intercompany debt of the Canadian operations. Should the Company distribute Canadian earnings, we may be subject to U.S. income taxes and Canadian withholding taxes. It is not practicable to estimate the amount of such taxes that may be payable if such a distribution occurs. The Company currently has no foreign tax credits to offset such taxes.

(5) INCOME TAXES: (Continued)

Accounting for Uncertainty in Income Taxes

The Company adopted authoritative accounting guidance regarding accounting for uncertainty in income taxes on January 1, 2007. As a result of the implementation of this guidance, 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 table below sets forth the reconciliation of the beginning and ending balances of the total amounts of unrecognized tax benefits. The Company records interest accrued related to unrecognized tax benefits in income tax 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 this guidance.

	Year Ended December 31,	
	2009	2008
	(In Thousands)	
Gross unrecognized tax benefits at beginning of period	$ 3,167	3,167
Increases in tax positions for prior years	1,138	—
Decreases in tax positions for acquired entities	(1,640)	—
Gross unrecognized tax benefits at end of period	$ 2,665	3,167

(6) SHAREHOLDERS' EQUITY:

Common Stock

At December 31, 2009, the Company had 200.0 million shares of Common Stock, par value $.10 per share, authorized and 112.3 million shares outstanding.

In May 2009, the Company issued 14,375,000 shares of common stock at a price of $18.25 per share. Net proceeds from this offering were $256.2 million after deducting underwriting discounts and commissions and offering expenses. Forest used the net proceeds from the offering to repay a portion of the outstanding borrowings under its U.S. credit facility.

(6) SHAREHOLDERS' EQUITY: (Continued)

Preferred Stock

Forest has 10,000,000 shares of preferred stock, par value $.01 per share, authorized under its Articles of Incorporation. Of those, 7,350,000 shares are designated as Senior Preferred Stock and 2,650,000 shares are designated as Junior Preferred stock.

Capital Surplus

In 2008, Forest recorded $12.4 million to capital surplus as a result of an adjustment to the pro rata distribution of common stock related to Forest's spin-off of its Gulf of Mexico operations, which occurred in 2006 by means of a special dividend. The adjustment to the pro rata distribution resulted from the resolution of certain matters that were the subject of arbitration.

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:

The table below sets forth total stock-based compensation recorded during the years ended December 31, 2009, 2008, and 2007, and the remaining unamortized amounts and the weighted average amortization period remaining as of December 31, 2009.

	Stock Options	Restricted Stock	Phantom Stock Units	Total[1]
		(In Thousands)		
Year ended December 31, 2009:				
Total stock-based compensation costs	$ 793	25,448	2,345	28,586
Less: stock-based compensation costs capitalized	(326)	(10,301)	(1,101)	(11,728)
Stock-based compensation costs expensed	$ 467	15,147	1,244	16,858
Unamortized stock-based compensation costs as of December 31, 2009	$ 1,366	31,610	6,474[2]	39,450
Weighted average amortization period remaining	1.1 years	1.6 years	2.3 years	1.7 years
Year ended December 31, 2008:				
Total stock-based compensation costs	$ 2,677	23,565	242	26,484
Less: stock-based compensation costs capitalized	(1,171)	(8,546)	(124)	(9,841)
Stock-based compensation costs expensed	$ 1,506	15,019	118	16,643
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

(1) The Company also maintains an employee stock purchase plan (which is not included in the table above) under which $.6 million, $.5 million, and $.4 million of compensation cost was recognized for the years ended December 31, 2009, 2008, and 2007, respectively.

(2) Based on the closing price of the Company's Common Stock on December 31, 2009.

(7) **STOCK-BASED COMPENSATION: (Continued)**

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, 2009, the Company had 776,189 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 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 approximately 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, 2009, the Company had 200,636 shares available to be issued under the 2001 Plan.

Stock Options

The following table summarizes stock option activity in the Company's stock-based compensation plans for the years ended December 31, 2009, 2008, and 2007.

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)[1]	Number of Shares Exercisable
Outstanding at January 1, 2007	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
Granted	—	—		
Exercised	(788,641)	21.14	30,372	
Cancelled	(55,598)	32.88		
Outstanding at December 31, 2008	2,097,267	21.13	376	1,898,316
Granted	—	—		
Exercised	(170,702)	17.96	671	
Cancelled	(108,146)	23.82		
Outstanding at December 31, 2009	1,818,419	$21.26	$ 7,387	1,722,216

(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.

(7) STOCK-BASED COMPENSATION: (Continued)

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

The fair value of each option granted in 2007 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 2007:

	2007
Expected life of options	5.4 years
Risk free interest rates	4.65% - 5.13%
Estimated volatility	32%
Dividend yield	0.0%
Weighted average fair market value of options granted during the year	$16.14

The following table summarizes information about options outstanding at December 31, 2009:

	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 of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)
$14.73 – 16.75	381,127	3.33	$15.29	$2,856	381,127	3.33	$15.29	$2,856
16.82 – 16.85	427,995	3.37	16.84	2,541	427,995	3.37	16.84	2,541
16.88 – 20.47	259,686	1.84	18.61	1,083	259,686	1.84	18.61	1,083
20.60 – 21.32	421,159	4.56	20.63	907	421,159	4.56	20.63	907
23.35 – 42.41	328,452	6.26	36.87	—	232,249	5.76	34.57	—
$14.73 – 42.41	1,818,419	3.94	$21.26	$7,387	1,722,216	3.74	$20.08	$7,387

(7) **STOCK-BASED COMPENSATION: (Continued)**

Restricted Stock and Phantom Stock Units

The following table summarizes the restricted stock and phantom stock unit activity for the years ended December 31, 2009, 2008, and 2007. 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[1]		
	Number of Shares	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)	Number of Shares	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)[2]
Unvested at January 1, 2007	627,450	$43.15		77,950	$44.32	
Awarded	784,700	42.17		90,700	41.01	
Vested	(82,450)	30.26	$ 3,690	—	—	$ —
Forfeited	(48,700)	42.20		(4,150)	44.17	
Unvested at December 31, 2007	1,281,000	43.41		164,500	42.50	
Awarded	759,295	62.55		84,754	61.73	
Vested	(473,800)	45.66	10,325	(70,300)	45.06	1,332
Forfeited	(75,700)	46.14		(15,000)	45.15	
Unvested at December 31, 2008	1,490,795	52.31		163,954	51.10	
Awarded	839,618	18.21		360,578	18.22	
Vested	(119,145)	45.50	2,302	(12,109)	33.28	236
Forfeited	(182,585)	42.91		(37,360)	34.41	
Unvested at December 31, 2009	2,028,683	$39.44		475,063	$27.91	

(1) Of the unvested units of phantom stock at December 31, 2009, 226,800 units can be settled in cash, shares of common stock, or a combination of both, while the remaining 248,263 units can only be settled in cash.

(2) Of the 12,109 phantom stock units that vested during 2009, 7,429 units were settled in shares of common stock with a fair value of $.1 million and 4,680 units were settled in cash for $.1 million. Of the 70,300 phantom stock units that vested in 2008, 70,050 units were settled in shares of common stock with a fair value of $1.3 million and 250 units were settled in cash for $14,000.

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.

Employee Stock Purchase Plan

The Company has a 1999 Employee Stock Purchase Plan (the "ESPP"), under which it is authorized to issue up to 800,000 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, 2009, the Company had 460,596 shares available for issuance under the ESPP.

(7) STOCK-BASED COMPENSATION: (Continued)

The fair value of each stock purchase right granted under the ESPP during 2009, 2008, and 2007 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:

	2009	2008	2007
Expected option life	3 months	3 months	3 months
Risk free interest rates	0.08% - 0.22%	0.85% - 1.96%	3.92% - 5.07%
Estimated volatility	62%	76%	26%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of purchase rights granted	$4.70	$11.72	$10.88

(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") 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 Supplemental Executive Retirement Plan 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," and together with the "Forest Pension Plan," the "Pension Plan"). The Wiser Pension Plan was curtailed and all benefit accruals were suspended effective December 11, 1998. In conjunction with the Houston Exploration acquisition in June 2007, Forest assumed a non-qualified unfunded supplementary retirement plan (the "Houston Exploration SERP," and together with the "Supplemental Executive Retirement Plan," the "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, and the SERP are hereinafter collectively referred to as the "Plans."

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

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

(8) EMPLOYEE BENEFITS: (Continued)

the SERP and the other postretirement benefits plans in 2010 through 2014 and in the aggregate for the years 2015 through 2019 in the following amounts:

	2010	2011	2012	2013	2014	2015-2019
			(In Thousands)			
Forest Pension Plan[1]	$2,383	2,355	2,309	2,315	2,235	10,368
SERP	135	132	129	126	122	556
Wiser Pension Plan[1]	869	861	850	845	833	4,084
Postretirement benefits (U.S.)	596	600	576	566	559	2,810
Postretirement benefits (Canada)	47	50	53	54	54	308

(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 2010 totaling $.1 million to the Plans and $.4 million for the Postretirement Benefit plans, net of retiree contributions and expected Medicare reimbursements, as applicable.

Benefit Obligations

The following table sets forth the estimated benefit obligations associated with the Company's pension and postretirement benefits.

	Pension Benefits		Postretirement Benefits	
	2009	2008	2009	2008
		(In Thousands)		
Benefit obligation at the beginning of the year	$39,780	40,421	7,619	8,576
Acquisition	—	—	—	(585)
Service cost	—	—	543	518
Interest cost	2,207	2,277	493	495
Actuarial loss (gain)	2,475	399	853	(599)
Benefits paid	(3,257)	(3,317)	(740)	(679)
Medicare reimbursements	—	—	59	59
Retiree contributions	—	—	68	68
Impact of foreign currency exchange rate	—	—	162	(234)
Benefit obligation at the end of the year	$41,205	39,780	9,057	7,619

Fair Value of Plan Assets

The Company's Pension Plan assets measured at fair value on a recurring basis at December 31, 2009 are set forth by level within the fair value hierarchy in the table below (see Note 9 for information on the fair value hierarchy). There were no changes to the valuation techniques used during the period. The SERP and the postretirement benefit plans do not have any assets at

(8) EMPLOYEE BENEFITS: (Continued)

December 31, 2009. During the year, the amount of contributions and Medicare reimbursements, in the case of the postretirement benefit plans, equals the amount of benefits paid.

Description	Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Using Significant Other Observable Inputs (Level 2)	Using Significant Unobservable Inputs (Level 3)	Total
		(In Thousands)		
Investment funds—equities:				
Research equity portfolio[1]	$ —	10,251	—	10,251
International stock fund[2]	9,625	—	—	9,625
Investment funds—fixed income:				
Short-term fund[3]	1,375	—	—	1,375
Bond fund[4]	7,992	—	—	7,992
Oil and gas royalty interests[5]	—	—	136	136
	$18,992	10,251	136	29,379

(1) This investment fund's assets are primarily large capitalization U.S. equities. The investment approach of this fund, which typically holds 110 - 113 securities, focuses on diversifying the investment portfolio by delegating the equity selection process to research analysts with expertise in their respective industries. Industry weights are kept similar to those of the S&P 500 Index. As of December 31, 2009, the sector weighting of this fund was comprised of the following: information technology (21%), health care (15%), financials (14%), energy (13%), consumer discretionary (10%), and other (27%). The fair value of this investment fund was determined based on the net asset value per unit provided by the investee.

(2) This investment fund seeks long-term growth of principal and income by investing primarily in a diversified portfolio of equity securities issued by foreign, medium-to-large companies from at least three different foreign countries, including emerging markets. The fund, which typically holds 50 - 100 securities, seeks to invest in solid, well-established global leaders with emphasis on strong corporate governance, positive future growth opportunities, and growing returns on capital. As of December 31, 2009, the sector weighting of this fund, which seeks diversification across regions, countries, and market sectors, was comprised of the following: financials (21%), consumer discretionary (17%), health care (14%), information technology (11%), industrials (11%), and other (26%). As of December 31, 2009, the geographic diversification of this fund was: Europe, excluding the United Kingdom, (48%), United Kingdom (14%), Japan (13%), and other (25%). The fair value of this investment fund was determined based on the fund's net asset value per unit, which is directly observable in the marketplace.

(3) This investment fund's assets are high-quality money market instruments and short-term fixed income securities. This fund is actively managed as an enhanced cash strategy, seeking to derive excess returns versus money market fund indices by capturing term, transactional liquidity, credit, and volatility premiums. As of December 31, 2009, the sector weighting of this fund was comprised of the following: government-related (35%), investment grade credit (33%), mortgage (11%), and other (21%). The fair value of this investment fund was determined based on the fund's net asset value per unit, which is directly observable in the marketplace.

(4) This investment fund consists of a diversified portfolio of bonds that is managed to maximize return in a risk-controlled framework. The fund's main investments are intermediate maturity fixed income securities with a duration between three and six years, with a maximum of 10% of the portfolio being invested in securities below Baa grade, and up to 30% of the portfolio being invested in non-U.S. dollar denominated securities. As of December 31, 2009, the sector weighting of this fund was comprised of the following: government-related (32%), investment grade credit (18%), mortgage (17%), foreign-developed (16%), and other (17%). The fair value of this investment fund was determined based on the fund's net asset value per unit, which is directly observable in the marketplace.

(5) The oil and gas royalty interests are valued at their discounted estimated future cash flows, which approximate fair value.

(8) EMPLOYEE BENEFITS: (Continued)

The following table sets forth a rollforward of the fair value of the Plan assets.

	Pension Benefits		Postretirement Benefits	
	2009	2008	2009	2008
	(In Thousands)			
Fair value of plan assets at beginning of the year	$24,451	37,831	—	—
Actual return on plan assets	6,341	(10,652)	—	—
Retiree contributions	—	—	68	68
Medicare reimbursements	—	—	59	59
Employer contribution	1,844	589	613	552
Benefits paid	(3,257)	(3,317)	(740)	(679)
Fair value of plan assets at the end of the year	$29,379	24,451	—	—

The following table presents a reconciliation of the beginning and ending balances of the Company's Pension Plan assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the year ended December 31, 2009.

	Year Ended December 31, 2009
	Oil and Gas Royalty Interests
	(In Thousands)
Balance at beginning of period	$136
Actual return on plan assets	45
Purchases, sales, and settlements (net)	—
Transfers in and/or out of Level 3[1]	(45)
Balance at end of period	$136

(1) Returns earned on the oil and gas royalties are transferred out and invested in the Pension Plan's other investment funds.

Investments of the Plans

The Pension Plan's 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 funding levels. The Company continually reviews the levels of funding and investment strategy for the Pension Plans. Generally, the strategy includes allocating the Pension Plan's assets between equity securities and fixed income securities, depending on economic conditions and funding needs, although the strategy does not define any specified minimum exposure for any point in time. The equity and fixed income asset allocation levels in place from time to time are intended to achieve an appropriate balance between capital appreciation, preservation of capital, and current income.

The overall investment goal for the Pension Plan assets is to achieve an investment return that allows the Pension 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 Index. The Pension Plan's investment target is a 65% equity/35% bond split with discretion to vary the mix temporarily, in response to market conditions.

The weighted average asset allocations of the Forest Pension Plan and Wiser Pension Plan at December 31, 2009 and 2008 are set forth in the following table:

	Forest Pension Plan		Wiser Pension Plan	
	2009	2008	2009	2008
Fixed income securities	32%	39%	31%	38%
Equity securities	67%	59%	69%	61%
Other	1%	2%	0%	1%
	100%	100%	100%	100%

(8) EMPLOYEE BENEFITS: (Continued)

Funded Status

The following table sets forth the funded status of the Company's pension and postretirement benefits.

	Pension Benefits		Postretirement Benefits	
	2009	2008	2009	2008
	(In Thousands)			
Excess of benefit obligation over plan assets	$(11,827)	(15,329)	(9,057)	(7,619)
Unrecognized actuarial loss (gain)	17,642	22,026	(913)	(1,932)
Net amount recognized	$ 5,815	6,697	(9,970)	(9,551)
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability—noncurrent	$(11,827)	(15,329)	(9,057)	(7,619)
Accumulated other comprehensive income—net actuarial loss (gain)	17,642	22,026	(913)	(1,932)
Net amount recognized	$ 5,815	6,697	(9,970)	(9,551)

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,	
	2009	2008
	(In Thousands)	
Projected benefit obligation	$41,205	39,780
Accumulated benefit obligation	41,205	39,780
Fair value of plan assets	29,379	24,451

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, 2009, 2008, and 2007:

	Pension Benefits			Postretirement Benefits		
	2009	2008	2007	2009	2008	2007
	(In Thousands)					
Service cost	$ —	—	—	543	518	467
Interest cost	2,207	2,277	2,247	493	495	453
Expected return on plan assets	(1,600)	(2,534)	(2,562)	—	—	—
Recognized actuarial loss (gain)	2,119	726	778	(105)	(91)	(35)
Total net periodic expense	$ 2,726	469	463	931	922	885
Assumptions used to determine net periodic expense:						
Discount rate	5.84%	5.77%	5.64% & 5.90%	6.12% & 6.74%	5.39% & 6.02%	3.98% & 5.75%
Expected return on plan assets	7%	7%	7%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:						
Discount rate	5.04%	5.84%	5.77%	5.55% & 4.50%	6.12% & 6.74%	5.39% & 6.02%

(8) EMPLOYEE BENEFITS: (Continued)

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 expected rate-of-return on plan assets was determined based on historical returns.

The Company estimates that net periodic expense for the year ended December 31, 2010, will include expense of $1.6 million resulting from the amortization of its related accumulated actuarial loss included in accumulated other comprehensive income at December 31, 2009.

The assumed health care cost trend rate for the next year and thereafter that was used to measure the expected cost of benefits covered by the U.S. Postretirement Benefits was 5.5%. The assumed health care cost trend rates that were used to measure the expected cost of benefits covered by the Canadian Postretirement Benefits were 6.5% in 2010, 6.2% in 2011, 5.9% in 2012, 5.6% in 2013, 5.3% in 2014, and 5.0% thereafter for the dental plan and 10.0% in 2010, 9.5% in 2011, 9.0% in 2012, 8.5% in 2013, 8.0% in 2014, and 7.5% 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 2009:

	Postretirement Benefits	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	$ 241	(180)
Effect on postretirement benefit obligation	1,507	(1,183)

Other Employee Benefit Plans

Forest sponsors various defined contribution plans in the United States and Canada under which the Company contributed matching contributions equal to $4.1 million in 2009, $3.9 million in 2008, and $3.1 million in 2007.

Forest also 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. On January 1, 2008, the Company adopted authoritative accounting guidance that required the Company to recognize a liability for the estimated cost of maintaining the insurance policies during the postretirement periods of the retirees and former executives. Upon adoption, Forest recorded a $9.0 million liability as a change in accounting principle through a cumulative effect adjustment to retained earnings. The weighted average discount rate used to determine the initial postretirement benefit obligation and accretion expense for 2008 was 5.55%. The weighted average discount rate used to determine the accretion expense for 2009 was 5.64%. The weighted average discount rate used to determine the postretirement benefit obligation as of December 31, 2009 was 4.01%. The Company's estimate of costs expected to be paid in 2010 to maintain these life insurance policies is $1.0 million. Accretion of the discounted life insurance obligations was $.4 million and $.5 million for the years ended December 31, 2009 and 2008, respectively. As of December 31, 2009, the Consolidated Balance Sheet includes a liability associated with the life insurance policies of $8.2 million and an asset of $3.1 million, with the asset representing the estimated cash surrender value of the life insurance policies.

(9) FAIR VALUE MEASUREMENTS:

In September 2006, the FASB issued authoritative guidance that clarified the definition of fair value, established a framework for measuring fair value, and expanded disclosures about fair value measurements. The Company adopted the provisions of this guidance as of January 1, 2008 for all financial and nonfinancial assets and liabilities recognized or disclosed at fair value on a recurring basis. The Company has also adopted this guidance as it relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis (e.g. those measured at fair value in a business combination and impairments of goodwill and other long-lived assets) as of January 1, 2009. The adoption of this guidance did not materially impact the Company's financial position, results of operations, or cash flow.

The authoritative guidance established a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions. The Company uses the income approach to value financial instruments under the Level 2 and Level 3 hierarchies.

The Company's assets and liabilities measured at fair value on a recurring basis at December 31, 2009 are set forth by level within the fair value hierarchy in the table below.

Description	Using Significant Other Observable Inputs (Level 2)	Using Significant Unobservable Inputs (Level 3)	Total
		(In Thousands)	
Assets:			
Derivative instruments[1]	$36,199	—	36,199
Equity securities[2]	—	—	—
Debt securities[2]	—	—	—
Liabilities:			
Derivative instruments[1]	42,184	—	42,184

(1) The Company's derivative assets and liabilities include oil and gas commodity swaps and collars as well as interest rate swaps and swaptions (see Note 10). The Company utilized present value techniques for valuing its swaps and option-pricing models for valuing its collars. Inputs to these valuation techniques include published forward prices, volatilities, and credit risk considerations, including the incorporation of published interest rates and credit spreads. All of the significant inputs are observable, either directly or indirectly; therefore, the Company's derivative instruments are included within the Level 2 fair value hierarchy.

(2) The Company's equity and debt securities are comprised of a zero coupon senior subordinated note due from Pacific Energy Resources, Ltd. ("PERL") in 2014 at a principal amount at stated maturity of $60.8 million (the "PERL Note") and 10 million shares of PERL common stock (the "PERL Shares"), both received as consideration for the sale of the Company's Alaska assets in 2007. The PERL Shares and Note, each presently valued at zero, are included within the Level 3 fair value hierarchy. The Company used its own assumptions about the assumptions that market participants would use regarding future cash flows and risk-adjusted discount rates in valuing the PERL Shares and Note. In March 2009, PERL filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. PERL has indicated that the value of its assets is less than the amount of its senior unsubordinated debt.

(9) FAIR VALUE MEASUREMENTS: (Continued)

The following table presents a reconciliation of the beginning and ending balances of the Company's assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the year ended December 31, 2009.

	Year Ended December 31, 2009		Year Ended December 31, 2008
	Equity Securities	Debt Securities	Debt Securities
		(In Thousands)	
Balance at beginning of period	$ —	1,670	15,023
Total gains or (losses) (realized/unrealized):			
Included in earnings	(657)	(1,670)	(13,353)
Included in other comprehensive income	—	—	—
Purchases, sales, issuances, and settlements (net)	—	—	—
Transfers in and/or out of Level 3[(1)]	657	—	—
Balance at end of period	—	—	1,670

(1) The Company's investment in PERL common stock was previously valued within the Level 1 fair value hierarchy until March 2009 when PERL's common stock was suspended from trading for failure to meet the continued stock exchange listing requirements. As a result, the Company's investment in PERL common stock, presently valued at zero, is now included within the Level 3 fair value hierarchy as there is no longer an active market for this investment.

Gains and losses (realized and unrealized) included in earnings related to the Company's assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2009 and December 31, 2008 are reported in the Consolidated Statements of Operations as follows:

	Year Ended December 31, 2009		Year Ended December 31, 2008	
			Debt Securities	
	Equity Securities	Debt Securities		Interest and
	Other, Net	Other, Net	Other, Net	other[(1)]
		(In Thousands)		
Total losses or (gains) included in earnings for the period	$657	1,670	15,027	(1,674)
Change in unrealized losses or (gains) relating to assets still held at end of period	$657	1,670	15,027	—

(1) Represents imputed interest income on the PERL Note.

(9) FAIR VALUE MEASUREMENTS: (Continued)

The fair values and carrying amounts of the Company's financial instruments are summarized below as of the dates indicated.

	December 31, 2009		December 31, 2008	
	Carrying Amount	Fair Value[(1)]	Carrying Amount	Fair Value[(1)]
	(In Thousands)			
Assets:				
Cash and cash equivalents	$ 467,221	467,221	2,205	2,205
Other investments	—	—	2,327	2,327
Derivative instruments	36,199	36,199	173,995	173,995
Liabilities:				
Derivative instruments	42,184	42,184	3,884	3,884
Credit facilities	—	—	1,284,415	1,284,415
8% senior notes due 2011	289,221	296,400	291,350	256,500
7% senior subordinated notes due 2013	110	112	1,087	912
8½% senior notes due 2014	575,971	630,000	—	—
7¾% senior notes due 2014	156,678	151,938	158,219	123,000
7¼% senior notes due 2019	1,000,534	992,500	1,000,590	780,000

(1) The Company used various assumptions and methods in estimating the fair values of its financial instruments. The carrying amount of cash and cash equivalents approximated fair value due to the short original maturities (three months or less) and high liquidity of the cash equivalents. The carrying amount of the Credit Facilities approximated fair value since borrowings bear interest at variable rates. The fair values of the senior notes and senior subordinated notes were estimated based on quoted market prices, if available, or quoted market prices of comparable instruments. The fair values of the derivative instruments and other investments are discussed above. See also Note 10 to the Consolidated Financial Statements for more information on the derivative instruments.

(10) DERIVATIVE INSTRUMENTS:

Commodity Derivatives

Forest periodically enters into derivative instruments such as swap, basis swap, and collar agreements as an attempt to moderate the effects of wide fluctuations in commodity prices on the Company's cash flow and to manage the exposure to commodity price risk. Forest's commodity derivative instruments generally serve as effective economic hedges of commodity price exposure; however, the Company has elected not to designate its derivatives as hedging instruments. As such, the Company recognizes all changes in fair value of its derivative instruments as unrealized gains or losses on derivative instruments in the Consolidated Statement of Operations.

In March 2008, the FASB issued authoritative guidance that requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This guidance was effective for fiscal years and interim periods beginning after November 15, 2008. Accordingly, Forest has adopted this guidance as of January 1, 2009.

(10) DERIVATIVE INSTRUMENTS: (Continued)

The table below sets forth Forest's outstanding commodity swaps and costless collars as of December 31, 2009.

	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Barrels Per Day	Weighted Average Hedged Price per Bbl
Swaps:				
Calendar 2010	200	$6.28	3,000	$76.06
Collars:				
Calendar 2010	—	—	2,000	60.00/98.50[1]

(1) Represents weighted average hedged floor and ceiling price per Bbl.

Forest also uses basis swaps in connection with natural gas swaps in order to fix the price differential between the NYMEX Henry Hub price and the index price at which the natural gas production is sold. The table below sets forth Forest's outstanding basis swaps as of December 31, 2009.

Basis Swaps

Remaining Swap Term	Index	Bbtu Per Day	Weighted Average Hedged Price Differential per MMBtu
Calendar 2010	Centerpoint	30	$ (.95)
Calendar 2010	Houston Ship Channel	50	(.29)
Calendar 2010	Mid Continent	60	(1.04)
Calendar 2010	NGPL TXOK	40	(.44)

Interest Rate Derivatives

Forest periodically enters into interest rate derivative agreements in an attempt to normalize the mix of fixed and floating interest rates within its debt portfolio. The table below sets forth Forest's outstanding fixed-to-floating interest rate swaps as of December 31, 2009.

Interest Rate Swaps

Remaining Swap Term	Notional Amount (In Thousands)	Weighted Average Floating Rate	Weighted Average Fixed Rate
January 2010 – February 2014	$500,000	1 month LIBOR + 5.89%	8.50%
January 2010 – May 2014[1]	100,000	3 month LIBOR + 5.00%	7.75%

(1) Forest voluntarily terminated this interest rate swap subsequent to December 31, 2009 for proceeds of $750,000, including accrued interest.

In addition to the interest rate swaps, during the year ended December 31, 2009, Forest entered into certain interest rate swaptions, which enable the counterparties to exercise options to enter into interest rate swaps with Forest in exchange for a premium paid to Forest. The premiums received on these swaptions are amortized as realized gains on derivatives over the term of the related swaption. Forest entered into these interest rate swaptions because its targeted floating interest rates were not attainable at that time in the interest rate swap market, yet premiums were available from counterparties for the option to swap Forest's 8.5% fixed rate for the floating rates it had targeted. The table below sets forth Forest's outstanding interest rate swaption as of December 31, 2009.

Interest Rate Swaption

Option Term	Swap Term	Premium Received (In Thousands)	Notional Amount (In Thousands)	Floating Rate	Fixed Rate
Oct 2009 – Jan 2010 . .	Jan 2010 – Feb 2014	$550	$100,000	1 month LIBOR + 5.73%	8.50%

Subsequent to December 31, 2009, the interest rate swaption in the table above expired unexercised and Forest entered into the following interest rate swaption:

Interest Rate Swaption

Option Term	Swap Term	Premium Received (In Thousands)	Notional Amount (In Thousands)	Floating Rate	Fixed Rate
Jan 2010 – April 2010	May 2010 – Feb 2014	$350	$100,000	3 month LIBOR + 5.50%	8.50%

Fair Value and Gains and Losses

The table below summarizes the location and fair value amounts of Forest's derivative instruments reported in the Consolidated Balance Sheets as of the dates indicated. These derivative instruments are not designated as hedging instruments for accounting purposes. For financial reporting purposes, Forest does not offset asset and liability fair value amounts recognized for derivative instruments with the same counterparty under its master netting arrangements. See Note 9 to the Consolidated Financial Statements for more information on Forest's derivative instruments.

	December 31, 2009	December 31, 2008
	(In Thousands)	
Assets:		
Commodity derivatives:		
Current assets: derivative instruments	$35,454	169,387
Derivative instruments	—	4,608
Interest rate derivatives:		
Current assets: derivative instruments	189	—
Derivative instruments	556	—
Total assets	36,199	173,995
Liabilities:		
Commodity derivatives:		
Current liabilities: derivative instruments	40,843	1,284
Derivative instruments	—	2,600
Interest rate derivatives:		
Current liabilities: derivative instruments	515	—
Derivative instruments	826	—
Total liabilities	42,184	3,884
Net derivative fair value	$(5,985)	170,111

The table below summarizes the amount of derivative instrument gains and losses reported in the Consolidated Statements of Operations as realized and unrealized (gains) losses on derivative

(10) DERIVATIVE INSTRUMENTS: (Continued)

instruments, net, for the periods indicated. These derivative instruments are not designated as hedging instruments for accounting purposes.

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
Commodity derivatives:			
Realized (gains) losses[1]	$(297,208)	55,072	(75,491)
Unrealized losses (gains)	175,499	(216,769)	112,778
Interest rate derivatives:			
Realized (gains) losses[2]	(10,958)	889	(474)
Unrealized losses (gains)	519	(4,721)	4,721
Realized and unrealized (gains) losses on derivative instruments, net	$(132,148)	(165,529)	41,534

(1) The years ended December 31, 2008 and 2007 include proceeds of $19.2 million and $6.9 million, respectively, received upon termination of certain oil and gas swaps and collars.

(2) The year ended December 31, 2008 includes $.4 million of net proceeds received upon termination of certain interest rate swaps.

Due to the volatility of oil and natural gas prices, the estimated fair values of Forest's commodity derivative instruments are subject to large fluctuations from period to period. Forest has experienced the effects of these commodity price fluctuations in both the current period and prior periods and expects that volatility in commodity prices will continue.

Credit Risk

Forest executes with each of its derivative counterparties an International Swap and Derivatives Association, Inc. ("ISDA") Master Agreement, which is a standard industry form contract containing general terms and conditions applicable to many types of derivative transactions. Additionally, Forest executes, with each of its derivative counterparties, a Schedule, which modifies the terms and conditions of the ISDA Master Agreement according to the parties' requirements and the specific types of derivatives to be traded. None of these counterparties require collateral beyond that already pledged under the Credit Facilities. All but one of the counterparties is a lender, or an affiliate of a lender, under the Credit Facilities, which provide that any security granted by Forest under the Credit Facilities shall also extend to and be available to those lenders that are counterparties to derivative transactions with Forest. The remaining counterparty, a purchaser of Forest's natural gas production, generally owes money to Forest and therefore does not require collateral under the ISDA Master Agreement and Schedule it has executed with Forest.

The ISDA Master Agreements and Schedules contain cross-default provisions whereby a default under the Credit Facilities will also cause a default under the derivative agreements. Such events of default include non-payment, breach of warranty, non-performance of 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. In addition, 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. None of these events of default are specifically credit-related, but some could arise if there were a general deterioration of Forest's credit. The ISDA Master Agreements and Schedules contain a further credit-related termination event that would occur if Forest were to merge with another entity and the creditworthiness of the resulting entity was materially weaker than that of Forest.

(10) DERIVATIVE INSTRUMENTS: (Continued)

The vast majority of Forest's derivative counterparties are all financial institutions that are engaged in similar activities and have similar economic characteristics that, in general, could cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions. Forest does not require the posting of collateral for its benefit under its derivative agreements. However, Forest's ISDA Master Agreements contain netting provisions whereby if on any date amounts would otherwise be payable by each party to the other, then on such date the party that owes the larger amount will pay the excess of that amount over the smaller amount owed by the other party, thus satisfying each party's obligations. These provisions apply to all derivative transactions with the particular counterparty. If all counterparties failed, Forest would be exposed to a risk of loss equal to this net amount owed to us, the fair value of which was $18.2 million at December 31, 2009. If Forest suffered an event of default, each counterparty could demand immediate payment, subject to notification periods, of the net obligations due to it under the derivative agreements. At December 31, 2009, Forest owed a net derivative liability to nine counterparties, the fair value of which was $24.2 million.

(11) 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, 2008, Anschutz owned approximately 8% of Forest's outstanding common stock; however, as of December 31, 2009, Anschutz owned less than 5% of Forest's outstanding common stock.

In 1998, Forest purchased certain oil and gas assets from Anschutz, including two concessions in South Africa. Over the years, the parties have entered into agreements concerning the development of these concession blocks. In March 2003, Forest entered into a Participation Agreement regarding the development of offshore South Africa acreage, including the Ibhubesi Gas Field, with The Petroleum Oil and Gas Corporation of South Africa (Pty) Limited ("PetroSA") and Anschutz Overseas South Africa (Pty) Limited ("Anschutz Overseas"). As of February 25, 2010, 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.

(12) COMMITMENTS AND CONTINGENCIES:

The table below shows the Company's future rental payments under non-cancelable operating leases and unconditional purchase obligations as of December 31, 2009.

	2010	2011	2012	2013	2014	After 2014	Total
			(In Thousands)				
Operating leases[1]	$19,082	17,451	16,420	15,240	9,117	4,890	82,200
Unconditional purchase obligations[2]	7,771	4,741	106	1,759	—	—	14,377
	$26,853	22,192	16,526	16,999	9,117	4,890	96,577

(1) Includes future rental payments for office facilities and equipment, drilling rigs, compressors, and vehicles under the remaining terms of non-cancelable operating leases.

(2) Includes unconditional purchase obligations for seismic purchases and pipeline capacity.

Net rental payments under non-cancelable operating leases applicable to exploration and development activities and capitalized to oil and gas properties were $10.1 million in 2009, $15.4 million in 2008, and $8.0 million in 2007. Net rental payments under non-cancelable operating leases charged to expense amounted to $14.9 million in 2009, $5.4 million in 2008, and $4.5 million in 2007. The Company has no leases that are accounted for as capital leases.

(12) COMMITMENTS AND CONTINGENCIES: (Continued)

Forest, in the ordinary course of business, is a party to various lawsuits, claims, and proceedings. While the Company believes 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.

(13) COSTS, EXPENSES, AND OTHER:

The table below sets forth the components of "Other, net" in the Consolidated Statement of Operations for the periods indicated.

	Year Ended December 31,		
	2009	2008	2007
	(In Thousands)		
Unrealized losses on other investments, net	$ 2,327	34,042	4,948
Unrealized foreign currency exchange (gains) losses, net	(17,974)	19,481	(7,694)
Realized foreign currency exchange (gains) losses, net	(88)	959	(7,721)
Rig stacking costs	8,940	—	—
Debt extinguishment costs	—	97	12,215
Franchise taxes	1,410	1,612	2,322
Other, net	6,462	3,464	154
	$ 1,077	59,655	4,224

(14) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In Thousands, Except Per Share Amounts)			
2009				
Oil and gas sales	$ 194,659	181,630	177,184	214,357
Net earnings (loss)[1]	$(1,177,773)	37,141	172,311	45,188
Basic earnings (loss) per share	$ (12.32)	.36	1.53	.40
Diluted earnings (loss) per share	(12.32)	.36	1.53	.40
2008				
Oil and gas sales	$ 376,587	515,078	474,237	281,269
Net earnings (loss)[1]	$ (4,732)	(68,018)	429,007	(1,382,580)
Basic earnings (loss) per share[2]	$ (.05)	(.78)	4.77	(14.50)
Diluted earnings (loss) per share[2]	(.05)	(.78)	4.71	(14.50)

(1) Net earnings have been subject to large fluctuations due to ceiling test write-downs of oil and gas properties as discussed in Note 1 and due to Forest's election not to use cash flow hedge accounting as discussed in Note 10. As discussed in Note 1, in January 2010, the FASB issued oil and gas reserve estimation and disclosure authoritative accounting guidance effective for reporting periods ending on or after December 31, 2009. This authoritative accounting guidance affected Forest's fourth quarter depletion calculation in that the oil and gas reserves used in the calculation were based on the average oil and gas prices during the twelve-month period prior to December 31, 2009 rather than the period-end spot prices, which were required pursuant to the previous authoritative accounting guidance, that were used for all the previous quarters presented. The effect on net earnings and per share amounts was not significant for the fourth quarter ended December 31, 2009.

(2) As discussed in Note 1, in June 2008, the FASB issued authoritative guidance that addressed whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method. This guidance was effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, Forest adopted this guidance as of January 1, 2009. All prior period earnings per share data presented have been adjusted retrospectively to conform to the provisions of this guidance.

(15) GEOGRAPHICAL SEGMENTS:

At December 31, 2009, Forest conducted operations in one industry segment, oil and gas exploration and production, and had three reportable geographical business segments: United States, Canada, and International. Forest's remaining activities were not significant and therefore were not reported as a separate segment, but have been 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, 2009			
	United States	Canada	International	Total Company
	(In Thousands)			
Oil and gas sales	$ 655,579	112,251	—	767,830
Costs and expenses:				
Lease operating expenses	119,472	27,505	—	146,977
Production and property taxes	40,147	2,756	—	42,903
Transportation and processing costs	12,855	8,060	—	20,915
Depletion	235,994	55,947	—	291,941
Ceiling test write-down of oil and gas properties	1,376,822	199,021	—	1,575,843
Accretion of asset retirement obligations	7,206	1,009	96	8,311
Segment loss	$(1,136,917)	(182,047)	(96)	(1,319,060)
Capital expenditures(1)	$ 497,975	88,278	9,875	596,128
Goodwill(2)	$ 239,420	16,488	—	255,908
Long-lived assets(3)	$ 1,717,219	454,937	87,051	2,259,207
Total assets(2)	$ 3,080,921	515,636	88,133	3,684,690

(1) Includes estimated discounted asset retirement obligations of $2.9 million related to assets placed in service during the year ended December 31, 2009.

(2) As of December 31, 2009.

(3) Consists of net property and equipment as of December 31, 2009.

A reconciliation of segment loss to consolidated loss before income taxes is as follows:

	Year Ended December 31, 2009
	(In Thousands)
Segment loss	$(1,319,060)
Interest and other income	625
General and administrative expense	(71,076)
Depreciation and amortization expense	(11,681)
Interest expense	(163,487)
Realized and unrealized gains on derivative instruments, net	132,148
Other, net	(1,077)
Loss before income taxes	$(1,433,608)

(15) GEOGRAPHICAL SEGMENTS: (Continued)

	Oil and Gas Operations			
	Year Ended December 31, 2008			
	United States	Canada	International	Total Company
	(In Thousands)			
Oil and gas sales	$ 1,396,669	250,502	—	1,647,171
Costs and expenses:				
Lease operating expenses	131,756	36,074	—	167,830
Production and property taxes	78,488	3,659	—	82,147
Transportation and processing costs	9,866	9,606	—	19,472
Depletion	437,952	85,859	—	523,811
Ceiling test write-down of oil and gas properties	2,369,055	—	—	2,369,055
Accretion of asset retirement obligations	6,387	1,130	85	7,602
Segment earnings (loss)	$(1,636,835)	114,174	(85)	(1,522,746)
Capital expenditures[1]	$ 2,560,940	197,953	7,216	2,766,109
Goodwill[2]	$ 239,420	14,226	—	253,646
Long-lived assets[3]	$ 3,758,709	676,783	77,672	4,513,164
Total assets[2]	$ 4,476,489	726,895	79,414	5,282,798

(1) Includes estimated discounted asset retirement obligations of $15.0 million related to assets placed in service during the year ended December 31, 2008.

(2) As of December 31, 2008.

(3) Consists of net property and equipment as of December 31, 2008.

A reconciliation of segment loss to consolidated loss before income taxes is as follows:

	Year Ended December 31, 2008
	(In Thousands)
Segment loss	$(1,522,746)
Interest and other income	3,589
General and administrative expense	(74,732)
Depreciation and amortization expense	(8,370)
Interest expense	(125,679)
Realized and unrealized gains on derivative instruments, net	165,529
Gain on sale of assets	21,063
Other, net	(59,655)
Loss before income taxes	$(1,601,001)

(15) GEOGRAPHICAL SEGMENTS: (Continued)

	Oil and Gas Operations Year Ended December 31, 2007			
	United States	Canada	International	Total Company
	(In Thousands)			
Oil and gas sales	$ 892,818	190,263	—	1,083,081
Costs and 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
Segment earnings (loss)	$ 389,125	59,776	(50)	448,851
Capital expenditures[1]	$2,807,936	173,218	15,853	2,997,007
Goodwill[2]	$ 248,138	17,480	—	265,618
Long-lived assets[3]	$4,239,119	712,938	73,758	5,025,815
Total assets[2]	$4,828,582	791,714	75,252	5,695,548

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

(2) As of December 31, 2007.

(3) Consists of net property and equipment as of December 31, 2007.

A reconciliation of segment earnings to consolidated earnings before income taxes is as follows:

	Year Ended December 31, 2007
	(In Thousands)
Segment earnings	$ 448,851
Interest and other income	3,454
General and administrative expense	(63,751)
Depreciation and amortization expense	(5,109)
Interest expense	(113,162)
Realized and unrealized losses on derivative instruments, net	(41,534)
Gain on sale of assets	7,176
Other, net	(4,224)
Earnings before income taxes	$ 231,701

Forest had revenue from one purchaser, which is reported in the United States segment, that accounted for 10% or more of Forest's consolidated revenues in 2009. This purchaser represented $108.6 million of consolidated revenues. Forest had revenue from two purchasers, which is reported in the United States segment, that each accounted for 10% or more of Forest's consolidated revenue in 2008. These purchasers represented $213.8 million and $196.2 million of consolidated revenues, respectively. There were no purchasers that accounted for 10% or more of Forest's consolidated revenues in 2007.

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION:

The Company's 8% senior notes due 2011, 8½% senior notes due 2014, 7¾% senior notes due 2014, and 7¼% senior notes due 2019 have been 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, 2009 and 2008, and for the three years in the period ended December 31, 2009 on an issuer (parent company), guarantor subsidiary, non-guarantor subsidiaries, eliminating entries, and consolidated basis. Eliminating entries presented are necessary to combine the entities.

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS

(In Thousands)

	December 31, 2009					December 31, 2008				
	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	$ 456,978	379	9,864	—	**467,221**	1,226	74	905	—	**2,205**
Accounts receivable	79,857	24,406	22,671	(580)	**126,354**	106,941	22,003	28,584	(302)	**157,226**
Deferred income taxes	6,589	519	—	—	**7,108**	—	—	—	—	**—**
Other current assets	115,663	797	12,849	—	**129,309**	304,424	471	8,723	—	**313,618**
Total current assets	659,087	26,101	45,384	(580)	**729,992**	412,591	22,548	38,212	(302)	**473,049**
Property and equipment, at cost	7,093,082	1,074,610	1,657,986	—	**9,825,678**	7,327,978	1,259,337	1,465,891	—	**10,053,206**
Less accumulated depreciation, depletion and amortization	5,502,530	994,005	1,069,936	—	**7,566,471**	4,145,061	727,858	667,123	—	**5,540,042**
Net property and equipment	1,590,552	80,605	588,050	—	**2,259,207**	3,182,917	531,479	798,768	—	**4,513,164**
Investment in subsidiaries	308,424	—	—	(308,424)	**—**	577,405	—	—	(577,405)	**—**
Note receivable from subsidiary	135,529	—	—	(135,529)	**—**	93,052	—	—	(93,052)	**—**
Goodwill	216,460	22,960	16,488	—	**255,908**	216,460	22,960	14,226	—	**253,646**
Due from (to) parent and subsidiaries net	215,679	(60,884)	(154,795)	—	**—**	391,074	141,656	(532,730)	—	**—**
Deferred income taxes	395,519	—	—	(2,458)	**393,061**	—	—	—	—	**—**
Other assets	44,087	6	2,429	—	**46,522**	40,607	5	2,327	—	**42,939**
	$3,565,337	68,788	497,556	(446,991)	**3,684,690**	4,914,106	718,648	320,803	(670,759)	**5,282,798**
LIABILITIES AND SHAREHOLDERS' EQUITY										
Current liabilities:										
Accounts payable and accrued liabilities	$ 238,935	6,825	39,122	(580)	**284,302**	338,754	27,631	58,858	(302)	**424,941**
Current portion of long-term debt	156,678	—	—	—	**156,678**	—	—	—	—	**—**
Other current liabilities	86,633	64	7,343	—	**94,040**	88,064	1,165	7,241	—	**96,470**
Total current liabilities	482,246	6,889	46,465	(580)	**535,020**	426,818	28,796	66,099	(302)	**521,411**
Long-term debt	1,865,836	—	—	—	**1,865,836**	2,641,246	—	94,415	—	**2,735,661**
Note payable to parent	—	—	135,529	(135,529)	**—**	—	—	93,052	(93,052)	**—**
Other liabilities	121,869	769	35,158	—	**157,796**	128,017	3,397	35,813	—	**167,227**
Deferred income taxes	16,232	4,446	28,664	(2,458)	**46,884**	45,113	61,383	79,091	—	**185,587**
Total liabilities	2,486,183	12,104	245,816	(138,567)	**2,605,536**	3,241,194	93,576	368,470	(93,354)	**3,609,886**
Shareholders' equity	1,079,154	56,684	251,740	(308,424)	**1,079,154**	1,672,912	625,072	(47,667)	(577,405)	**1,672,912**
	$3,565,337	68,788	497,556	(446,991)	**3,684,690**	4,914,106	718,648	320,803	(670,759)	**5,282,798**

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(In Thousands)

	2009 Parent Company	2009 Guarantor Subsidiary	2009 Combined Non-Guarantor Subsidiaries	2009 Eliminations	2009 Consolidated	2008 Parent Company	2008 Guarantor Subsidiary	2008 Combined Non-Guarantor Subsidiaries	2008 Eliminations	2008 Consolidated	2007 Parent Company	2007 Guarantor Subsidiary	2007 Combined Non-Guarantor Subsidiaries	2007 Eliminations	2007 Consolidated
	Year Ended December 31,														
Revenues															
Oil and gas sales	$ 520,792	132,644	114,394	—	**767,830**	1,128,110	109,094	409,967	—	**1,647,171**	649,708	73,588	362,489	(2,704)	**1,083,081**
Interest and other	17,666	92	(174)	(16,959)	**625**	19,908	430	340	(17,089)	**3,589**	17,772	63	1,920	(16,301)	**3,454**
Equity earnings in subsidiaries	(244,758)	—	—	244,758	—	(112,817)	—	—	112,817	—	2,745	1	(627)	(2,119)	—
Total revenue	293,700	132,736	114,220	227,799	**768,455**	1,035,201	109,524	410,307	95,728	**1,650,760**	670,225	73,652	363,782	(21,124)	**1,086,535**
Costs, expenses, and other:															
Lease operating expenses	99,459	19,259	28,259	—	**146,977**	108,680	14,422	44,728	—	**167,830**	79,745	15,853	71,875	—	**167,473**
Other direct operating costs	48,970	6,023	8,825	—	**63,818**	75,493	8,180	17,946	—	**101,619**	50,651	5,475	19,338	—	**75,464**
General and administrative	60,282	2,506	8,288	—	**71,076**	64,826	336	9,570	—	**74,732**	51,022	119	12,610	—	**63,751**
Depreciation, depletion, and amortization	197,501	47,637	58,484	—	**303,622**	361,443	25,780	144,958	—	**532,181**	229,069	19,186	142,083	—	**390,338**
Ceiling test write-down of oil and gas properties	1,155,777	218,567	201,499	—	**1,575,843**	1,881,808	34,015	453,232	—	**2,369,055**	—	—	—	—	—
Interest expense	147,330	12,256	20,456	(16,555)	**163,487**	111,316	—	31,452	(17,089)	**125,679**	74,727	9	54,727	(16,301)	**113,162**
Realized and unrealized (gains) losses on derivative instruments, net	(111,765)	(20,062)	(321)	—	**(132,148)**	(75,236)	(53,769)	(36,524)	—	**(165,529)**	7,750	7,181	26,603	—	**41,534**
Gain on sale of assets	—	—	—	—	—	—	—	(21,063)	—	**(21,063)**	—	—	(7,176)	—	**(7,176)**
Other, net	18,433	260	(9,305)	—	**9,388**	46,726	600	19,655	276	**67,257**	(51,363)	1,011	749	59,891	**10,288**
Total costs, expenses, and other	1,615,987	286,446	316,185	(16,555)	**2,202,063**	2,575,056	29,564	663,954	(16,813)	**3,251,761**	441,601	48,834	320,809	43,590	**854,834**
Earnings (loss) before income taxes	(1,322,287)	(153,710)	(201,965)	244,354	**(1,433,608)**	(1,539,855)	79,960	(253,647)	112,541	**(1,601,001)**	228,624	24,818	42,973	(64,714)	**231,701**
Income tax	(399,154)	(56,937)	(54,384)	—	**(510,475)**	(513,532)	28,586	(89,732)	—	**(574,678)**	59,318	9,242	(6,165)	—	**62,395**
Net earnings (loss)	$ (923,133)	(96,773)	(147,581)	244,354	**(923,133)**	(1,026,323)	51,374	(163,915)	112,541	**(1,026,323)**	169,306	15,576	49,138	(64,714)	**169,306**

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

(In Thousands)

	Year Ended December 31,											
	2009				2008				2007			
	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 (loss)	$ (678,375)	(96,773)	(147,985)	**(923,133)**	(913,506)	51,374	(164,191)	**(1,026,323)**	99,907	15,576	53,823	**169,306**
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:												
Depreciation, depletion, and amortization	197,501	47,637	58,484	**303,622**	361,443	25,780	144,958	**532,181**	229,069	19,186	142,083	**390,338**
Unrealized losses (gains) on derivative instruments, net	146,628	28,929	461	**176,018**	(110,904)	(69,091)	(41,495)	**(221,490)**	69,053	11,318	37,128	**117,499**
Deferred income tax	(469,969)	(56,937)	(54,384)	**(581,290)**	(521,281)	28,586	(93,122)	**(585,817)**	53,192	9,242	(6,038)	**56,396**
Ceiling test write-down of oil and gas properties	1,155,777	218,567	201,499	**1,575,843**	1,881,808	34,015	453,232	**2,369,055**	—	—	—	—
Other, net	33,387	334	(18,505)	**15,216**	53,485	180	1,019	**54,684**	14,154	192	(5,907)	**8,439**
Changes in operating assets and liabilities, net of effects of acquisitions and divestitures:												
Accounts receivable	27,084	(2,403)	11,109	**35,790**	20,872	3,709	18,273	**42,854**	6,825	449	(6,921)	**353**
Other current assets	34,239	(364)	(3,066)	**30,809**	(78,166)	56	(2,104)	**(80,214)**	(3,250)	2,107	2,700	**1,557**
Accounts payable and accrued liabilities	(22,322)	(7,984)	(17,650)	**(47,956)**	(3,532)	4,859	14,469	**15,796**	4,091	1,856	(15,539)	**(9,592)**
Accrued interest and other current liabilities	15,344	(1,571)	(1,696)	**12,077**	(30,258)	(549)	121	**(30,686)**	(3,226)	(207)	(22,618)	**(26,051)**
Net cash provided by operating activities	439,294	129,435	28,267	**596,996**	659,961	78,919	331,160	**1,070,040**	469,815	59,719	178,711	**708,245**
Investing activities:												
Acquisition of Houston Exploration, net of cash acquired	—	—	—	—	—	—	—	—	(775,365)	—	—	**(775,365)**
Capital expenditures for property and equipment	(456,959)	(104,218)	(107,541)	**(668,718)**	(1,828,225)	(124,247)	(452,021)	**(2,404,493)**	(423,526)	(30,605)	(365,773)	**(819,904)**
Proceeds from sales of assets	657,247	276,211	120,604	**1,054,062**	284,677	—	25,263	**309,940**	405,857	26,161	70,030	**502,048**
Other, net	27	—	1	**28**	933	(4)	131	**1,060**	—	—	—	—
Net cash provided (used) by investing activities	200,315	171,993	13,064	**385,372**	(1,542,615)	(124,251)	(426,627)	**(2,093,493)**	(793,034)	(4,444)	(295,743)	**(1,093,221)**
Financing activities:												
Proceeds from bank borrowings	747,000	—	121,533	**868,533**	2,847,000	—	356,360	**3,203,360**	1,308,000	—	228,526	**1,536,526**
Repayments of bank borrowings	(1,937,000)	—	(236,687)	**(2,173,687)**	(1,822,000)	—	(373,101)	**(2,195,101)**	(1,342,885)	—	(199,178)	**(1,542,063)**
Issuance of senior notes, net of issuance costs	559,767	—	—	**559,767**	247,188	—	—	**247,188**	739,176	—	—	**739,176**
Proceeds from common stock offering, net of offering costs	256,217	—	—	**256,217**	—	—	—	—	—	—	—	—
Repayments of Alaska Credit Agreements	—	—	—	—	—	—	—	—	—	—	(375,000)	**(375,000)**
Redemption of 8% senior notes	—	—	—	—	(265,000)	—	—	**(265,000)**				
Repurchase of 7% senior subordinated notes	(970)	—	—	**(970)**	(4,710)	—	—	**(4,710)**				
Net activity in investments of subsidiaries	213,865	(298,004)	84,139	—	(147,079)	42,755	104,324	—	(389,846)	(55,578)	445,424	—
Other, net	(22,736)	(3,119)	(869)	**(26,724)**	27,292	2,265	964	**30,521**	9,192	563	(8,842)	**913**
Net cash (used) provided by financing activities	(183,857)	(301,123)	(31,884)	**(516,864)**	882,691	45,020	88,547	**1,016,258**	323,637	(55,015)	90,930	**359,552**
Effect of exchange rate changes on cash	—	—	(488)	**(488)**	—	—	(285)	**(285)**	—	—	1,945	**1,945**
Net increase (decrease) in cash and cash equivalents	455,752	305	8,959	**465,016**	37	(312)	(7,205)	**(7,480)**	418	260	(24,157)	**(23,479)**
Cash and cash equivalents at beginning of period	1,226	74	905	**2,205**	1,189	386	8,110	**9,685**	771	126	32,267	**33,164**
Cash and cash equivalents at end of period	$ 456,978	379	9,864	**467,221**	1,226	74	905	**2,205**	1,189	386	8,110	**9,685**

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

Estimated Proved Oil and Gas Reserves

The reserve estimates as of December 31, 2009 presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance issued by the FASB effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's final rule, "Modernization of Oil and Gas Reporting," which was also effective for annual reports for fiscal years ending on or after December 31, 2009.

The new guidance includes updated definitions of proved oil and gas reserves, proved undeveloped oil and gas reserves, oil and gas producing activities and other terms used in estimating proved oil and gas reserves. Proved oil and gas reserves as of December 31, 2009 were calculated based on the prices for oil and gas during the twelve month period before the reporting date, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, rather than the year-end spot prices, which had been used in years prior to 2009. This average price is also used in calculating the aggregate amount and changes in future cash inflows related to the standardized measure of discounted future cash flows. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. The new guidance broadened the types of technologies that a company may use to establish reserve estimates and also broadened the definition of oil and gas producing activities to include the extraction of non-traditional resources, including bitumen extracted from oil sands as well as oil and gas extracted from shales. Prior period data presented throughout this footnote is not required to be, nor has it been, updated based on the new guidance.

The effect of adopting the new guidance negatively impacted the Company's estimated quantity of total proved reserves as of December 31, 2009 by approximately 317 Bcfe primarily due to pricing methodology changes and the five-year limit on proved undeveloped reserves, offset somewhat by the use of new technologies to establish proved undeveloped reserves.

The Company's estimates of its net proved, net proved developed, and net proved undeveloped oil and gas reserves and changes in its net proved oil and gas reserves for 2009, 2008, and 2007 are presented in the table below. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Existing economic conditions include the average prices for oil and gas during the twelve month period before the reporting date for 2009 and the year-end spot prices for oil and gas for 2008 and 2007, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Prices do not include the effects of commodity derivatives. Existing economic conditions include year-end cost estimates for all years presented. For the years ended December 31, 2009, 2008, and 2007, the Company engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

	Liquids (MBbls)				Gas (MMcf)				
	United States	Canada	Italy	Total	United States	Canada	Italy	Total	Total MMcfe
Balance at January 1, 2007	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
Revisions of previous estimates	(12,655)	(1,493)	—	(14,148)	(129,633)	1,813	—	(127,820)	(212,708)
Extensions and discoveries	17,571	4,112	—	21,683	351,628	50,817	—	402,445	532,543
Production	(6,929)	(1,102)	—	(8,031)	(118,120)	(23,313)	—	(141,433)	(189,619)
Sales of reserves in place	(3,884)	—	—	(3,884)	(69,554)	—	—	(69,554)	(92,858)
Purchases of reserves in place	19,024	—	—	19,024	397,392	—	—	397,392	511,536
Balance at December 31, 2008	100,284	8,836	—	109,120	1,719,583	237,515	56,308	2,013,406	2,668,126
Revisions of previous estimates	(3,633)	2,814	—	(819)	(357,352)	(33,020)	(4,570)	(394,942)	(399,856)
Extensions and discoveries	31,480	7,220	—	38,700	320,705	110,299	—	431,004	663,204
Production	(6,409)	(856)	—	(7,265)	(116,029)	(23,248)	—	(139,277)	(182,867)
Sales of reserves in place	(66,554)	(1,160)	—	(67,714)	(151,476)	(70,345)	—	(221,821)	(628,105)
Purchases of reserves in place	—	—	—	—	—	—	—	—	—
Balance at December 31, 2009	55,168	16,854	—	72,022	1,415,431	221,201	51,738	1,688,370	2,120,502
Proved developed reserves at:									
January 1, 2007	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
December 31, 2008	64,014	5,827	—	69,841	1,039,586	192,338	28,154	1,260,078	1,679,124
December 31, 2009	34,364	6,202	—	40,566	916,005	169,740	—	1,085,745	1,329,141
Proved undeveloped reserves at:									
January 1, 2007	33,930	654	—	34,584	172,131	39,769	—	211,900	419,404
December 31, 2007	25,507	2,372	—	27,879	387,387	44,760	28,154	460,301	627,575
December 31, 2008	36,270	3,009	—	39,279	679,997	45,177	28,154	753,328	989,002
December 31, 2009	20,804	10,652	—	31,456	499,426	51,461	51,738	602,625	791,361

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

Aggregate Capitalized Costs

The aggregate capitalized costs relating to oil and gas producing activities at the end of each of the years indicated were as follows:

	2009	2008	2007
		(In Thousands)	
Costs related to proved properties	$ 8,828,373	8,952,292	7,157,249
Costs related to unproved properties	828,645	964,027	568,510
	9,657,018	9,916,319	7,725,759
Less accumulated depletion	(7,511,661)	(5,502,782)	(2,742,539)
	$ 2,145,357	4,413,537	4,983,220

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities

The following costs were incurred in oil and gas property acquisition, exploration, and development activities during the years ended December 31, 2009, 2008, and 2007:

	United States	Canada	Italy	Total
		(In Thousands)		
2009				
Property acquisition costs:				
Proved properties	$ —	—	—	—
Unproved properties	—	—	—	—
Exploration costs	147,430	36,856	7,578	191,864
Development costs	350,545	51,422	—	401,967
Total costs incurred[(1)]	$ 497,975	88,278	7,578	593,831
2008				
Property acquisition costs:				
Proved properties	$ 804,616	—	—	804,616
Unproved properties	566,952	—	—	566,952
Exploration costs	290,066	51,628	3,157	344,851
Development costs	899,306	146,325	709	1,046,340
Total costs incurred[(1)]	$2,560,940	197,953	3,866	2,762,759
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	13,785	146,129
Development costs	518,020	137,351	—	655,371
Total costs incurred[(1)]	$2,807,936	173,218	13,785	2,994,939

(1) Includes amounts relating to estimated asset retirement obligations of $2.9 million, $15.0 million, and $37.8 million for assets placed in service in the years ended December 31, 2009, 2008, and 2007, respectively.

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

Results of Operations from Oil and Gas Producing Activities

Results of operations from oil and gas producing activities for the years ended December 31, 2009, 2008, and 2007 are presented below.

	United States	Canada	Italy	Total
		(In Thousands)		
2009				
Oil and gas sales	$ 655,579	112,251	—	767,830
Expenses:				
Production expense	172,474	38,321	—	210,795
Depletion expense	235,994	55,947	—	291,941
Ceiling test write-down of oil and gas properties	1,376,822	199,021	—	1,575,843
Accretion of asset retirement obligations	7,206	1,009	38	8,253
Income tax	(410,997)	(52,817)	—	(463,814)
Total expenses	1,381,499	241,481	38	1,623,018
Results of operations from oil and gas producing activities	$ (725,920)	(129,230)	(38)	(855,188)
Depletion rate per Mcfe	$ 1.53	1.97	—	1.60
2008				
Oil and gas sales	$ 1,396,669	250,502	—	1,647,171
Expenses:				
Production expense	220,110	49,339	—	269,449
Depletion expense	437,952	85,859	—	523,811
Ceiling test write-down of oil and gas properties	2,369,055	—	—	2,369,055
Accretion of asset retirement obligations	6,387	1,130	36	7,553
Income tax expense	(591,388)	33,721	—	(557,667)
Total expenses	2,442,116	170,049	36	2,612,201
Results of operations from oil and gas producing activities	$(1,045,447)	80,453	(36)	(965,030)
Depletion rate per Mcfe	$ 2.74	2.87	—	2.76
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 oil and gas producing activities	$ 249,429	43,290	—	292,719
Depletion rate per Mcfe	$ 2.42	2.68	—	2.47

The effect of adopting the oil and gas reserve estimation and disclosure authoritative accounting guidance issued by the FASB effective for reporting periods ending on or after December 31, 2009 on the Company's 2009 net loss and loss per share amounts was not significant.

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

Standardized Measure of Discounted Future Net Cash Flows

Future oil and gas sales are calculated applying the prices used in estimating the Company's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes were considered only to the extent provided by contractual arrangements in existence at each year-end. Future production and development costs, which include costs related to plugging of wells, removal of facilities and equipment, and site restoration, are calculated by estimating the expenditures to be incurred in producing and developing the proved oil and gas reserves at the end of each year, based on year-end costs and assuming continuation of existing economic conditions. 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 gas reserves, less the tax bases of the properties involved. The future income tax expenses give effect to tax deductions, credits, and allowances relating to the proved oil and gas reserves. All cash flow amounts, including income taxes, are discounted at 10%.

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, 2009			
	United States	Canada	Italy	Total
		(In Thousands)		
Future oil and gas sales	$ 6,632,073	1,956,498	797,286	9,385,857
Future production costs	(2,076,453)	(488,533)	(77,679)	(2,642,665)
Future development costs	(1,225,330)	(290,862)	(55,397)	(1,571,589)
Future income taxes	(264,263)	(250,675)	(245,394)	(760,332)
Future net cash flows	3,066,027	926,428	418,816	4,411,271
10% annual discount for estimated timing of cash flows	(1,737,138)	(427,738)	(193,396)	(2,358,272)
Standardized measure of discounted future net cash flows	$ 1,328,889	498,690	225,420	2,052,999

	December 31, 2008			
	United States	Canada	Italy	Total
		(In Thousands)		
Future oil and gas sales	$11,442,387	1,605,699	1,069,845	14,117,931
Future production costs	(3,193,613)	(349,487)	(72,891)	(3,615,991)
Future development costs	(1,895,124)	(145,415)	(37,067)	(2,077,606)
Future income taxes	(1,042,295)	(229,487)	(362,914)	(1,634,696)
Future net cash flows	5,311,355	881,310	596,973	6,789,638
10% annual discount for estimated timing of cash flows	(2,882,676)	(360,635)	(218,547)	(3,461,858)
Standardized measure of discounted future net cash flows	$ 2,428,679	520,675	378,426	3,327,780

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

	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

The adoption of the oil and gas reserve estimation and disclosure authoritative accounting guidance issued by the FASB effective for reporting periods ending on or after December 31, 2009 had an approximately $1.3 billion effect on the Company's standardized measure of discounted future net cash flows as of December 31, 2009, which decreased primarily due to a decrease in prices used in calculating the standardized measure of discounted future net cash flows under the new guidance.

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, 2009			
	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	$ 2,428,679	520,675	378,426	3,327,780
Changes resulting from:				
Sales of oil and gas, net of production costs	(483,096)	(73,930)	—	(557,026)
Net changes in prices and future production costs	(772,932)	(165,470)	(125,096)	(1,063,498)
Net changes in future development costs	(30,921)	27,703	(9,155)	(12,373)
Extensions, discoveries, and improved recovery	624,014	228,221	—	852,235
Development costs incurred during the period	38,353	10,755	—	49,108
Revisions of previous quantity estimates	(44,548)	31,247	(31,749)	(45,050)
Changes in production rates, timing, and other	(49,773)	(88,735)	(121,135)	(259,643)
Sales of reserves in place	(933,591)	(62,065)	—	(995,656)
Purchases of reserves in place	—	—	—	—
Accretion of discount on reserves at beginning of year	276,753	64,188	56,263	397,204
Net change in income taxes	275,951	6,101	77,866	359,918
Total change for year	(1,099,790)	(21,985)	(153,006)	(1,274,781)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$ 1,328,889	498,690	225,420	2,052,999

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

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2009 was based on average prices and year-end costs. The realized prices used in the computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2009 for gas were $3.32 per Mcf in the United States, $4.02 per Mcf in Canada, and $15.41 per Mcf in Italy, and the prices used for oil were $56.99 per barrel in the United States and $63.55 per barrel in Canada. The Henry Hub average natural gas price and West Texas Intermediate ("WTI") average oil price during the twelve-month period prior to December 31, 2009 were $3.87 per MMBtu and $61.08 per barrel, respectively.

	December 31, 2008			
	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	$ 3,616,736	631,348	291,051	4,539,135
Changes resulting from:				
Sales of oil and gas, net of production costs	(1,176,547)	(201,163)	—	(1,377,710)
Net changes in prices and future production costs	(3,134,532)	(330,774)	77,416	(3,387,890)
Net changes in future development costs	66,318	51,230	(416)	117,132
Extensions, discoveries, and improved recovery	1,337,152	266,578	—	1,603,730
Development costs incurred during the period	234,938	51,413	709	287,060
Revisions of previous quantity estimates	(316,030)	(15,250)	—	(331,280)
Changes in production rates, timing, and other	(109,990)	(43,484)	(44,457)	(197,931)
Sales of reserves in place	(214,872)	—	—	(214,872)
Purchases of reserves in place	904,289	—	—	904,289
Accretion of discount on reserves at beginning of year	470,619	78,485	48,125	597,229
Net change in income taxes	750,598	32,292	5,998	788,888
Total change for year	(1,188,057)	(110,673)	87,375	(1,211,355)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$ 2,428,679	520,675	378,426	3,327,780

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2008 was based on year-end prices and costs. The realized prices used for gas were $4.94 per Mcf in the United States, $5.64 per Mcf in Canada, and $19.00 per Mcf in Italy, and the prices used for oil were $38.73 per barrel in the United States and $30.23 per

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

barrel in Canada. The WTI spot price for oil and Henry Hub spot price for natural gas at December 31, 2008 were $44.60 per barrel and $5.71 per MMBtu, respectively.

	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, timing, 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	268,804	57,650	—	326,454
Net change in income taxes	(545,269)	(27,501)	(190,199)	(762,969)
Total change for year	1,472,875	180,845	291,051	1,944,771
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 year-end prices and costs. The realized prices used for gas were $6.20 per Mcf in the United States, $6.12 per Mcf in Canada, and $17.00 per Mcf in Italy, and the prices used for oil were $88.95 per barrel in the United States and $81.60 per barrel in Canada. The WTI spot price for oil and Henry Hub spot price for natural gas at December 31, 2007 were $95.98 per barrel and $6.80 per MMBtu, respectively.

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, Michael N. Kennedy, 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, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's 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, 2009. The effectiveness of our internal control over financial reporting as of December 31, 2009 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, 2009, 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, 2009, 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, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009 and our report dated February 26, 2010 expressed an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
February 26, 2010

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 Annual Report on 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, 2009 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 the procedures for shareholders of Forest to recommend nominees to the Board is set forth under the caption "Corporate Governance Principles and Information about the Board and its Committees—Consideration of Director Nominees—*Shareholder Nominees*"
- Information concerning 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—Board Structure; Committee Composition; Meetings"
- 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—Corporate Governance Guidelines and Code of Business Ethics"
- 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 and directors is set forth under the captions "Executive 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 "Security 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 "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" 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 caption "Principal Accountant Fees and Services" 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. Report of Independent Registered Public Accounting Firm
2. Consolidated Balance Sheets—December 31, 2009 and 2008
3. Consolidated Statements of Operations—Years Ended December 31, 2009, 2008, and 2007
4. Consolidated Statements of Shareholders' Equity—Years Ended December 31, 2009, 2008, and 2007
5. Consolidated Statements of Cash Flows—Years Ended December 31, 2009, 2008, and 2007
6. Notes to Consolidated Financial Statements—Years Ended December 31, 2009, 2008, and 2007

(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 Annual Report on 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, No. 3, and No. 4, incorporated herein by reference to Exhibit 3.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
4.1	Indenture dated December 7, 2001 between Forest Oil Corporation and State Street Bank and Trust Company, including the form of notes issued thereunder, 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).
4.2	Indenture dated as of April 25, 2002 between Forest Oil Corporation and State Street Bank and Trust Company, including the form of notes issued thereunder, 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).
4.3	Indenture dated as of June 6, 2007 between Forest Oil Corporation and U.S. Bank National Association, including the form of notes issued thereunder, 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).
4.4	Indenture dated as of February 17, 2009 between Forest Oil Corporation, Forest Oil Permian Corporation and U.S. Bank National Association, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.4 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (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 by and among Forest Oil Corporation, Forest Oil Permian Corporation and Banc of America Securities LLC, for itself and on behalf of the several Initial Purchasers dated as of May 22, 2008, incorporated herein by reference to Exhibit 4.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).

Exhibit Number	Description
4.7	Registration Rights Agreement by and among Forest Oil Corporation, Forest Oil Permian Corporation and J.P.Morgan Securities Inc., Banc of America Securities LLC, BNP Paribas Securities Corp., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., TD Securities (USA) Inc., Scotia Capital (USA) Inc. and Wachovia Capital Markets, LLC dated February 17, 2009, incorporated herein by reference to Exhibit 4.7 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
4.8	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).
4.9	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).
4.10	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 for the quarter ended June 30, 2007 (File No. 001-13515).
4.11	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 for the quarter ended June 30, 2007 (File No. 001-13515).
4.12	First Amendment dated May 9, 2008 to Second Amended and Restated Combined Credit Agreements dated June 6, 2007, among Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders party thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and JPMorgan Chase Bank N.A., Toronto Branch, as Canadian Administrative Agent, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 9, 2008 (File No. 001-13515).
4.13	Second Amendment dated March 16, 2009, to Second Amended and Restated Combined Credit Agreements dated June 6, 2007, among Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders that is party thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and JPMorgan Chase Bank, N.A., Toronto Branch, as Canadian Administrative Agent, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Forest Oil Corporation dated March 16, 2009 (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).

Exhibit Number	Description
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 for the quarter ended September 30, 2007 (File No. 001-13515).
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 for the quarter ended September 30, 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, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 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 for the quarter ended June 30, 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*	Amendment No. 1 to Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).

Exhibit Number	Description
10.18*	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 for the quarter ended June 30, 2007 (File No. 001-13515).
10.19*	Form of Non-Employee Director Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 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, 2008 (File No. 001-13515).
10.20*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2001 and 2007 Stock Incentive Plans, incorporated by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.21*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2001 and 2007 Stock Incentive Plans, incorporated by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.22*	Form of Non-Employee Director Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.23*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2009 (File No. 001-13515).
10.24*	Form of Phantom Stock Unit Agreement (for Canadian Employees) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2009 (File No. 001-13515).
10.25*	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).
10.26*	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).
10.27*	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).
10.28*	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).
10.29*	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).
10.30*	Form of Amendment to Form of Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.29 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.31*	Form of Amendment to Form of Severance Agreement for Grandfathered Executive Officer, incorporated herein by reference to Exhibit 10.30 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).

Exhibit Number	Description
10.32*	Forest Oil Corporation Pension Trust Agreement dated as of January 1, 2002 by and between Forest Oil Corporation and the trustees named therein or their successors, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2002, dated November 14, 2002 (File No. 001-13515).
10.33*	First Amendment to Forest Oil Corporation Pension Trust Agreement as Amended and Restated January 1, 2002, effective as of May 10, 2005, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2005 (File No. 001-13515).
10.34*	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).
10.35*	Forest Oil Corporation Amended and Restated Salary Deferral Compensation Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2003 (File No. 001-13515).
10.36*	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).
10.37*	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 for the quarter ended September 30, 2007 (File No. 001-13515).
10.38*	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).
10.39*	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).
10.40*	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 for the quarter ended September 30, 2007 (File No. 001-13515).
10.41*	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 for the quarter ended September 30, 2007 (File No. 001-13515).
10.42*	Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated herein by reference to Exhibit 10.41 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.43*	First Amendment to Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated November 9, 2009 (File No. 001-13515).
10.44	Forest Oil Corporation 2008 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.35 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).

Exhibit Number	Description
10.45	Forest Oil Corporation 2009 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2009 (File No. 001-13515).
10.46	Agreement and Plan of Merger dated as of September 9, 2005 among Forest Oil Corporation, SML Wellhead Corporation, Mariner Energy, Inc. and MEI Sub, Inc., incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2005 (No. 001-13515).
10.47	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).
10.48	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).
10.49	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).
10.50	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).
10.51	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).
10.52	Asset Purchase and Sale Agreement dated August 15, 2008, between Forest Oil Corporation and Cordillera Texas, L.P., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated September 30, 2008 (File No. 001-13515).
10.53	Amendment No. 1 to Asset Purchase and Sale Agreement dated August 15, 2008, between Forest Oil Corporation and Cordillera Texas, L.P., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated September 30, 2008 (File No. 001-13515).
10.54	Agreement for Purchase and Sale of Assets, dated as of August 5, 2009, by and among Forest Oil Corporation, Forest Oil Permian Corporation, Linn Operating, Inc. and Linn Energy Holdings, LLC, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated August 5, 2009 (File No. 001-13515).
10.55	Agreement for Purchase and Sale of Assets, dated as of November 25, 2009, by and among Forest Oil Corporation, Forest Oil Permian Corporation and SandRidge Exploration and Production, LLC, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated November 25, 2009 (File No. 001-13515).
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† Indicates Exhibits filed with this Annual Report on Form 10-K.

‡ The documents formatted in XBRL (Extensible Business Reporting Language) and attached as Exhibit 101 to this report are deemed not filed as part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act, are deemed not filed for purposes of section 18 of the Exchange Act, and otherwise, are not subject to liability under these sections.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 26, 2010

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, Michael N. Kennedy, 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 Annual Report on Form 10-K Annual Report for the year ended December 31, 2009, 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 26, 2010
/s/ MICHAEL N. KENNEDY Michael N. Kennedy	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2010
/s/ VICTOR A. WIND Victor A. Wind	Senior Vice President, Chief Accounting Officer and Corporate Controller (Principal Accounting Officer)	February 26, 2010
/s/ JAMES D. LIGHTNER James D. Lightner	Chairman of the Board	February 26, 2010
/s/ LOREN K. CARROLL Loren K. Carroll	Director	February 26, 2010
/s/ DOD. A. FRASER Dod. A. Fraser	Director	February 26, 2010
/s/ JAMES H. LEE James H. Lee	Director	February 26, 2010
/s/ PATRICK R. MCDONALD Patrick R. McDonald	Director	February 26, 2010
/s/ RAYMOND I. WILCOX Raymond I. Wilcox	Director	February 26, 2010

Index to 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, No. 3, and No. 4, incorporated herein by reference to Exhibit 3.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
4.1	Indenture dated December 7, 2001 between Forest Oil Corporation and State Street Bank and Trust Company, including the form of notes issued thereunder, 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).
4.2	Indenture dated as of April 25, 2002 between Forest Oil Corporation and State Street Bank and Trust Company, including the form of notes issued thereunder, 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).
4.3	Indenture dated as of June 6, 2007 between Forest Oil Corporation and U.S. Bank National Association, including the form of notes issued thereunder, 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).
4.4	Indenture dated as of February 17, 2009 between Forest Oil Corporation, Forest Oil Permian Corporation and U.S. Bank National Association, including the form of notes issued thereunder, incorporated herein by reference to Exhibit 4.4 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (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 by and among Forest Oil Corporation, Forest Oil Permian Corporation and Banc of America Securities LLC, for itself and on behalf of the several Initial Purchasers dated as of May 22, 2008, incorporated herein by reference to Exhibit 4.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).

Exhibit Number	Description
4.7	Registration Rights Agreement by and among Forest Oil Corporation, Forest Oil Permian Corporation and J.P.Morgan Securities Inc., Banc of America Securities LLC, BNP Paribas Securities Corp., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., TD Securities (USA) Inc., Scotia Capital (USA) Inc. and Wachovia Capital Markets, LLC dated February 17, 2009, incorporated herein by reference to Exhibit 4.7 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
4.8	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).
4.9	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).
4.10	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 for the quarter ended June 30, 2007 (File No. 001-13515).
4.11	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 for the quarter ended June 30, 2007 (File No. 001-13515).
4.12	First Amendment dated May 9, 2008 to Second Amended and Restated Combined Credit Agreements dated June 6, 2007, among Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders party thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and JPMorgan Chase Bank N.A., Toronto Branch, as Canadian Administrative Agent, incorporated by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 9, 2008 (File No. 001-13515).
4.13	Second Amendment dated March 16, 2009, to Second Amended and Restated Combined Credit Agreements dated June 6, 2007, among Forest Oil Corporation, Canadian Forest Oil Ltd., each of the lenders that is party thereto, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and JPMorgan Chase Bank, N.A., Toronto Branch, as Canadian Administrative Agent, incorporated herein by reference to Exhibit 4.1 to Form 8-K for Forest Oil Corporation dated March 16, 2009 (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).

Exhibit Number	Description
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 for the quarter ended September 30, 2007 (File No. 001-13515).
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 for the quarter ended September 30, 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, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 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 for the quarter ended June 30, 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*	Amendment No. 1 to Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).

Exhibit Number	Description
10.18*	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 for the quarter ended June 30, 2007 (File No. 001-13515).
10.19*	Form of Non-Employee Director Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 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, 2008 (File No. 001-13515).
10.20*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2001 and 2007 Stock Incentive Plans, incorporated by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.21*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2001 and 2007 Stock Incentive Plans, incorporated by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.22*	Form of Non-Employee Director Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
10.23*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2009 (File No. 001-13515).
10.24*	Form of Phantom Stock Unit Agreement (for Canadian Employees) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2009 (File No. 001-13515).
10.25*	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).
10.26*	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).
10.27*	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).
10.28*	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).
10.29*	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).
10.30*	Form of Amendment to Form of Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.29 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.31*	Form of Amendment to Form of Severance Agreement for Grandfathered Executive Officer, incorporated herein by reference to Exhibit 10.30 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).

Exhibit Number	Description
10.32*	Forest Oil Corporation Pension Trust Agreement dated as of January 1, 2002 by and between Forest Oil Corporation and the trustees named therein or their successors, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2002, dated November 14, 2002 (File No. 001-13515).
10.33*	First Amendment to Forest Oil Corporation Pension Trust Agreement as Amended and Restated January 1, 2002, effective as of May 10, 2005, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2005 (File No. 001-13515).
10.34*	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).
10.35*	Forest Oil Corporation Amended and Restated Salary Deferral Compensation Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2003 (File No. 001-13515).
10.36*	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).
10.37*	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 for the quarter ended September 30, 2007 (File No. 001-13515).
10.38*	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).
10.39*	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).
10.40*	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 for the quarter ended September 30, 2007 (File No. 001-13515).
10.41*	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 for the quarter ended September 30, 2007 (File No. 001-13515).
10.42*	Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated herein by reference to Exhibit 10.41 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).
10.43*	First Amendment to Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008), incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated November 9, 2009 (File No. 001-13515).
10.44	Forest Oil Corporation 2008 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.35 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2008 (File No. 001-13515).

Exhibit Number	Description
10.45	Forest Oil Corporation 2009 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2009 (File No. 001-13515).
10.46	Agreement and Plan of Merger dated as of September 9, 2005 among Forest Oil Corporation, SML Wellhead Corporation, Mariner Energy, Inc. and MEI Sub, Inc., incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2005 (No. 001-13515).
10.47	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).
10.48	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).
10.49	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).
10.50	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).
10.51	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).
10.52	Asset Purchase and Sale Agreement dated August 15, 2008, between Forest Oil Corporation and Cordillera Texas, L.P., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated September 30, 2008 (File No. 001-13515).
10.53	Amendment No. 1 to Asset Purchase and Sale Agreement dated August 15, 2008, between Forest Oil Corporation and Cordillera Texas, L.P., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated September 30, 2008 (File No. 001-13515).
10.54	Agreement for Purchase and Sale of Assets, dated as of August 5, 2009, by and among Forest Oil Corporation, Forest Oil Permian Corporation, Linn Operating, Inc. and Linn Energy Holdings, LLC, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated August 5, 2009 (File No. 001-13515).
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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, 27th Floor
Jersey City, NJ 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, Vice President – Corporate Planning and 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:
Marriott Hotel
1701 California Street
Denver, Colorado 80202
Wednesday, May 12, 2010 at 9:00 a.m. (MDT)

NON-GAAP FINANCIAL MEASURES

ADJUSTED EBITDA

In addition to reporting net earnings as defined under Generally Accepted Accounting Principals (GAAP), Forest also presented adjusted EBITDA, which is a non-GAAP performance measure. Adjusted EBITDA consists of net earnings before interest, taxes, depreciation, depletion, and amortization (adjusted EBITDA), among other items. Adjusted EBITDA does not represent and should not be considered an alternative to GAAP measurements, such as net earnings (its most comparable GAAP financial measure), and Forest's calculations thereof may not be comparable to similarly titled measures reported by other companies. Forest believes the measure is useful in evaluating its fundamental core operating performance. Forest also believes that adjusted EBITDA is useful to investors because similar measures are frequently used by securities analysts, investors, and other interested parties in their evaluation of companies in similar industries. Forest's management does not view adjusted EBITDA in isolation and also uses other measurements, such as net earnings and revenues to measure operating performance.

ADJUSTED DISCRETIONARY CASH FLOW

In addition to reporting cash provided by operating activities as defined under GAAP, Forest also presents adjusted discretionary cash flow, which is a non-GAAP liquidity measure. Adjusted discretionary cash flow consists of cash provided by operating activities before changes in operating assets and liabilities, among other items. Adjusted discretionary cash flow does not represent and should not be considered an alternative to GAAP measurements, such as cash provided by operating activities (its most comparable GAAP financial measure), and Forest's calculations thereof may not be comparable to similarly titled measures reported by other companies. Forest believes the measure is useful in managing its business, including in preparing its annual operating budget and financial projections. Forest also believes that adjusted discretionary cash flow is useful to investors because it assesses cash flow from operations before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. Forest's management does not view adjusted discretionary cash flow in isolation and also uses other measurements, such as cash provided by operating activities to measure operating performance.

Please reference Forest's 2009 10-K for our reconciliation of non-GAAP financial measures to the most comparable GAAP measures.

All-Sources Reserve Replacement Ratio

The reserve replacement ratio of 144% was calculated by dividing extensions and discoveries of 663 Bcfe less price and performance revisions of 400 Bcfe, by net sales volumes of 183 Bcfe.

All-Sources F&D Costs

Finding and development costs of $2.16 per Mcfe were calculated by dividing the sum of total costs from all capital activities, $569 million (which excludes capitalized interest, capitalized equity compensation and asset retirement obligations totaling $27 million), by extensions and discoveries of 663 Bcfe less price and performance revisions of 400 Bcfe.

Reserve Replacement Ratio, Excluding Price Revisions

The reserve replacement ratio, excluding price revisions, of 315% was calculated by dividing extensions and discoveries of 663 Bcfe less performance revisions of 88 Bcfe, by net sales volumes of 183 Bcfe.

F&D Costs, Excluding Price Revisions

Finding and development costs, excluding price revisions, of $0.99 per Mcfe were calculated by dividing the sum of total costs from all capital activities, $569 million (which excludes capitalized interest, capitalized equity compensation and asset retirement obligations totaling $27 million), by extensions and discoveries of 663 Bcfe less performance revisions of 88 Bcfe.

FORWARD-LOOKING STATEMENTS

This report included forward-looking statements, including those related to oil and gas reserve estimates, within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Please see Item 1, header "Forward-Looking Statements" and Item 1A, header "Risk Factors," in Forest's 2009 10-K for additional disclosures.

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