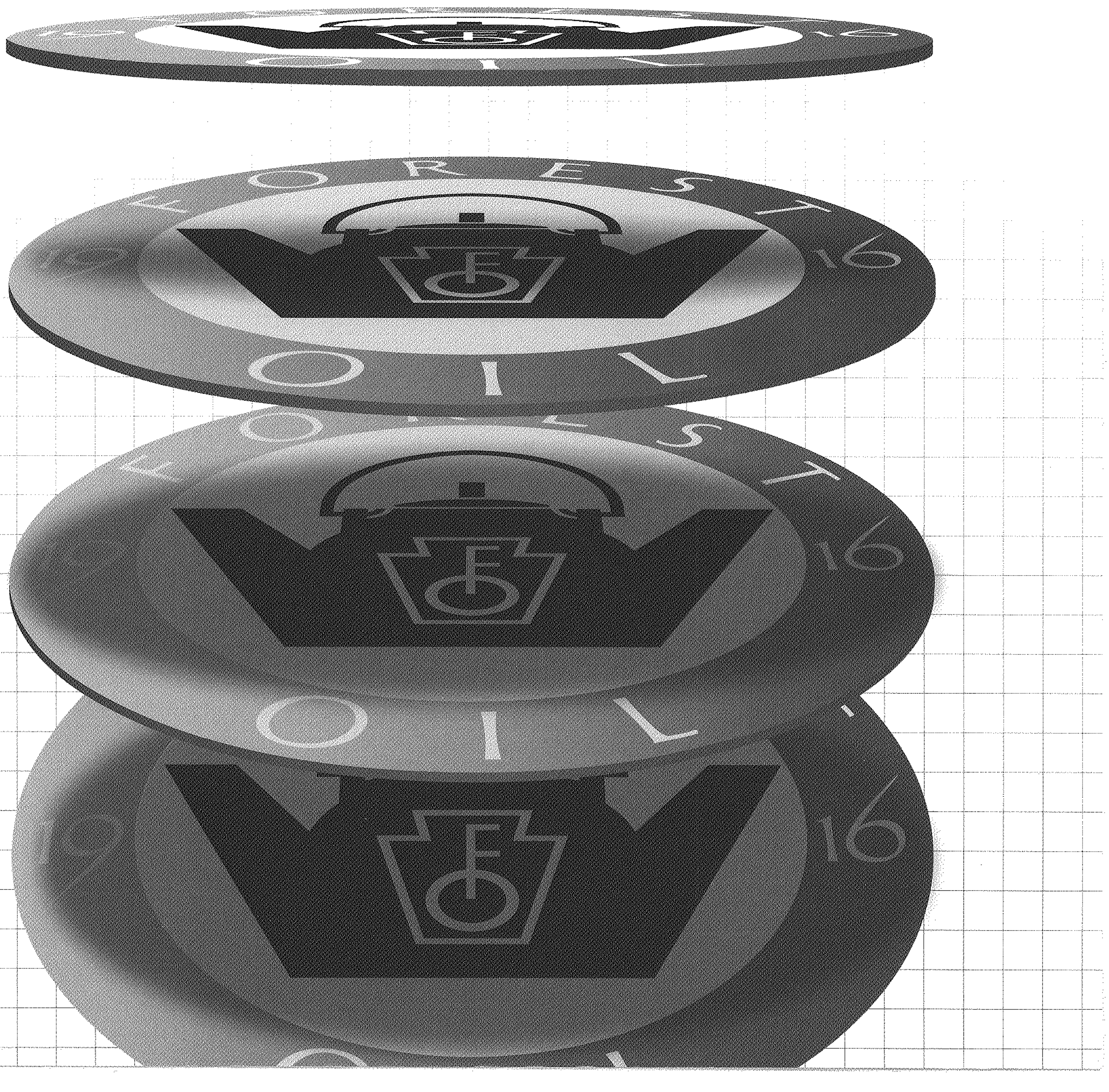
THE INTERVAL FACTOR

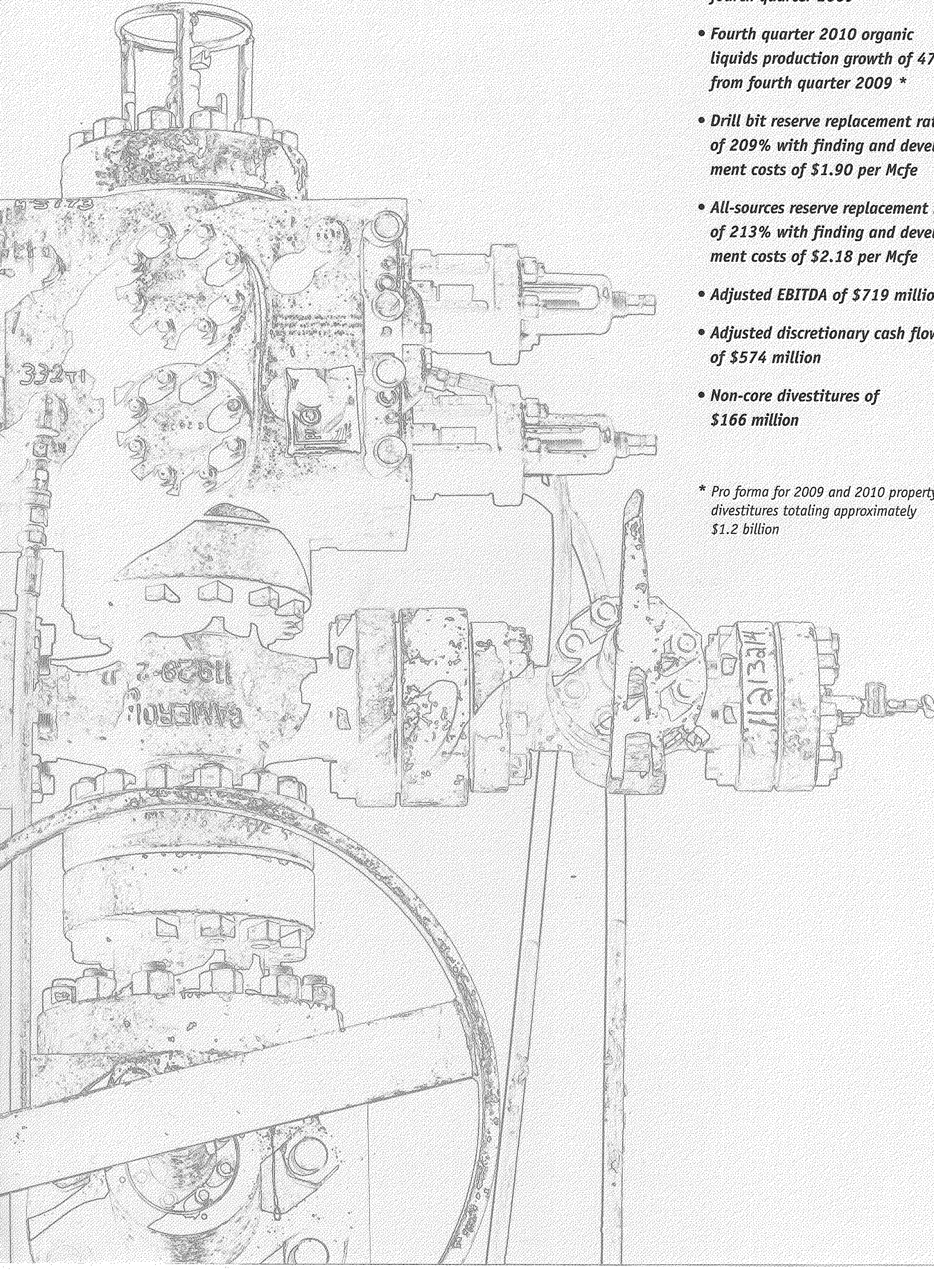
ANNUAL REPORT 2010



2010 HIGHLIGHTS

- *Fourth quarter 2010 organic production growth of 19% from fourth quarter 2009 **
- *Fourth quarter 2010 organic liquids production growth of 47% from fourth quarter 2009 **
- *Drill bit reserve replacement ratio of 209% with finding and development costs of $1.90 per Mcfe*
- *All-sources reserve replacement ratio of 213% with finding and development costs of $2.18 per Mcfe*
- *Adjusted EBITDA of $719 million*
- *Adjusted discretionary cash flow of $574 million*
- *Non-core divestitures of $166 million*

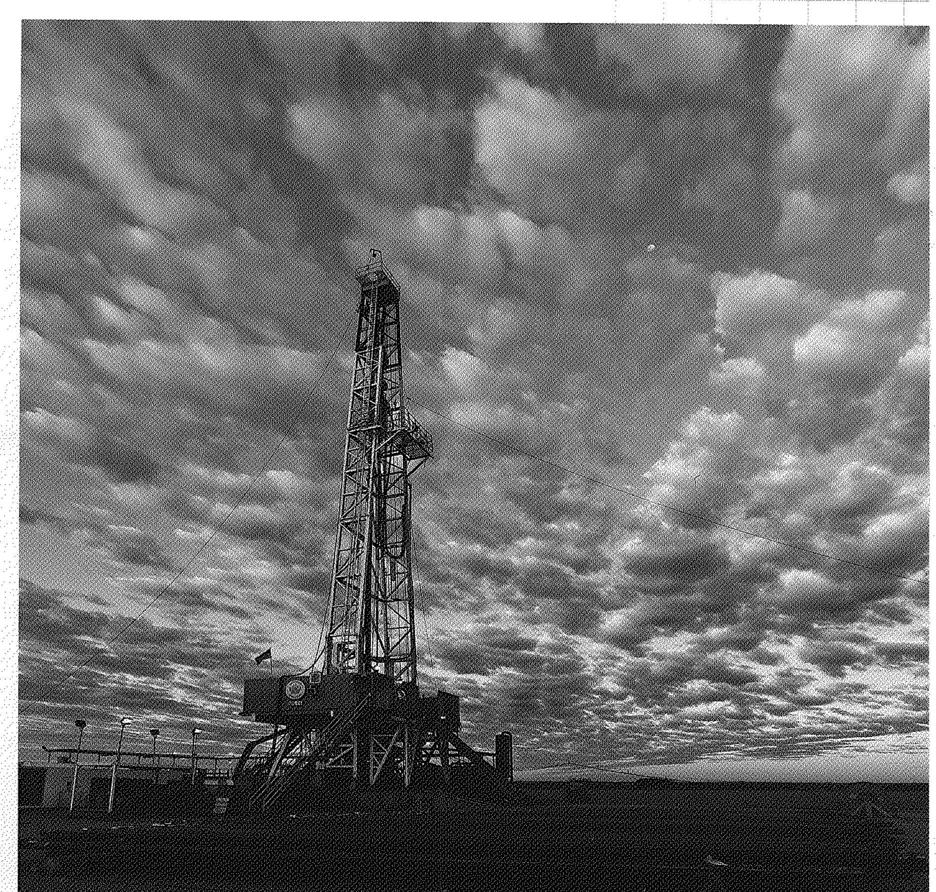
* *Pro forma for 2009 and 2010 property divestitures totaling approximately $1.2 billion*



Dear Fellow Shareholders

Our industry faced numerous challenges in 2010, including higher service costs, low natural gas prices and competition for North American resource plays from international and offshore operators. Higher service costs occured as a result of increased industry spending despite low natural gas prices, forcing prudent operators to focus on the cost side of the margin equation. Onshore operators also experienced expanded competition for resource plays from international and offshore operators attempting to gain a foothold in repeatable resource plays that have become prevalent in North America. Increased scrutiny placed on land access and new offshore regulatory permitting challenges have driven some companies to seek the opportunity for the low-risk, repeatable results, found in Forest's core areas.

Through our foresight, we have proactively assembled a high quality, onshore resource portfolio which provides us with repeatable drilling opportunities. Through the application of capital discipline, cost control, and most importantly horizontal drilling and completion techniques to our resource plays, we believe we can continually deliver profitable organic growth, both in terms of production and reserves. Our resource base offers multiple objectives in the same wellbore, which, through past vertical delineation efforts, have allowed us to better identify the optimal targets for horizontal drilling. We refer to these multiple objectives for horizontal drilling as the stacked *interval factor*, which provides us with a "portfolio within a portfolio" relative to our geographic asset base, allowing for multiple horizontal zone targets from the same drilling location. Our stacked *interval factor* continues to expand, as it has in the Texas Panhandle, with each new horizontal test. Additionally, our commodity balanced portfolio allows us to focus on drilling efforts that yield the best economic returns in any environment, with oil, natural gas and natural gas liquids prospects competing for the best returns.



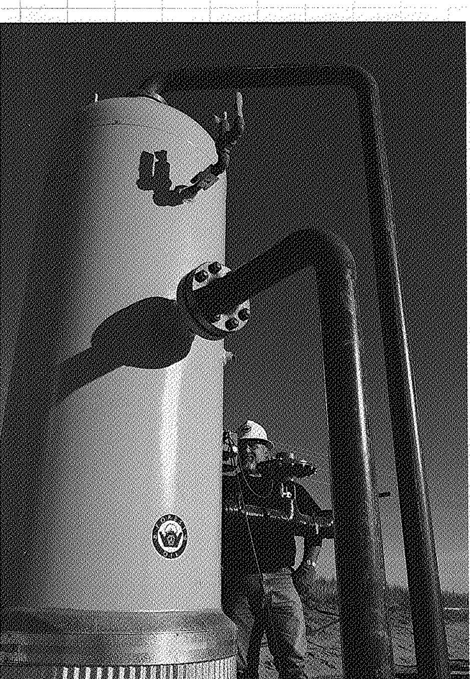
Lantern Drilling rig #14

We believe our portfolio based approach and the stacked *interval factor* can reward shareholders through the achievement of efficient growth with top quality operations and asset management. Our industry should not be in an "arms race" to growth; it should be in a race for the best returns on invested capital, or a focus on profitable organic growth as is the case at Forest. Our simple, focused strategy has proven successful and has not wavered.

Lantern Drilling rig #15

Profitable Organic Growth — As we moved *back on the bit* in 2010, we were successful in organic production and reserve growth from our high quality, commodity diverse asset base, while maintaining capital discipline. Our horizontal drilling programs yielded organic production growth of 19%, pro forma for divestitures, in 2010 while expanding our stacked *interval factor* opportunity set and acreage base. In 2011, we intend to direct capital to our highest rate-of-return projects, with approximately 80% directed to high liquids yielding projects.

Cost Control — As one of the lowest-cost operators in the industry, we scrutinize every cost in the organization, from the belief that costs drive economics, especially in resource plays. Cost may be the only item we can truly control in the exploration and production business and is important on everything from up-front acreage costs to drilling and operating costs. Our focus has enabled us to continue to reduce costs year over year. We view further cost reductions as a critical element in creating more objectives to be added to our stacked *interval factor*.



Manage the Portfolio — We divested approximately $1.2 billion of properties during the past two years, including $166 million in 2010, and have significantly rationalized the portfolio through the elimination of a large portion of our non-operated or non-core properties. With every acquisition and divestiture, we have upgraded our asset quality. A great example of this is our replacement of the production divested in Canada and the Permian Basin through organic growth in 2010. In 2011, we will look to expand our core areas through potential bolt-on acquisitions, and target further non-core or non-producing assets for divestiture. Through portfolio management we have added value for our shareholders and expect to continue value creating events in the future.

Financial Flexibility — Debt levels increased modestly in 2010 while production grew 19%, pro forma for divestitures. The ability to operate near expected cash flow and grow production and reserves is an advantage we have with our asset portfolio. Looking forward, we plan to continue our tried-and-true strategy of exploration and development capital expenditures near expected cash flow, thus maintaining our financial flexibility. We have successfully managed our lease obligations and we have minimal long-term service contract obligations, which provides additional flexibility.

THE INTERVAL FACTOR — 2011 PLAN

We plan to grow production and reserves with a capital program near expected cash flow; no surprise here. Our budget is technically designed to provide the best return on invested capital, focusing on liquids-rich drilling opportunities, and is directed towards states and provinces with favorable land and regulatory regimes. Our budget is based on technical work done in the past, not on lease expirations or emotion. With the current commodity price environment favoring liquid hydrocarbons, we have designed our budget accordingly, directing approximately 80% of our exploration and development capital to these projects. On the cost front, we will need to be more "completion efficient" going forward, as completion service costs in resource plays, specifically pumping services, will be a major issue in 2011. Our operations oriented background will prove beneficial in this light. Our ability to allocate capital based on our commodity-diverse portfolio and our focus on cost allows us to achieve an acceptable return on invested capital in various price environments.

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

The 2011 Texas Panhandle drilling program will receive approximately half of our budget as a result of success achieved in 2010 from the continued stacked *interval factor* expansion. Our plan includes horizontal drilling with a multitude of different intervals being developed. The remainder of the budget will primarily be allocated to Canada and the Eagle Ford Shale. The wild cards in 2011, which will provide for the opportunity to re-allocate capital on success, are new horizontal intervals in the Texas Panhandle, the Canada Deep Basin horizontal program, and success in the Eagle Ford Shale oil window.

We are fortunate to have favorable land access which provides us with a deep inventory of drilling locations. Although our capital budget is lower than in 2010 due to commodity price expectations, we look forward to another active year in drilling areas that have the ability to achieve attractive economic rates of return while, as always, striving to improve upon our cost structure.

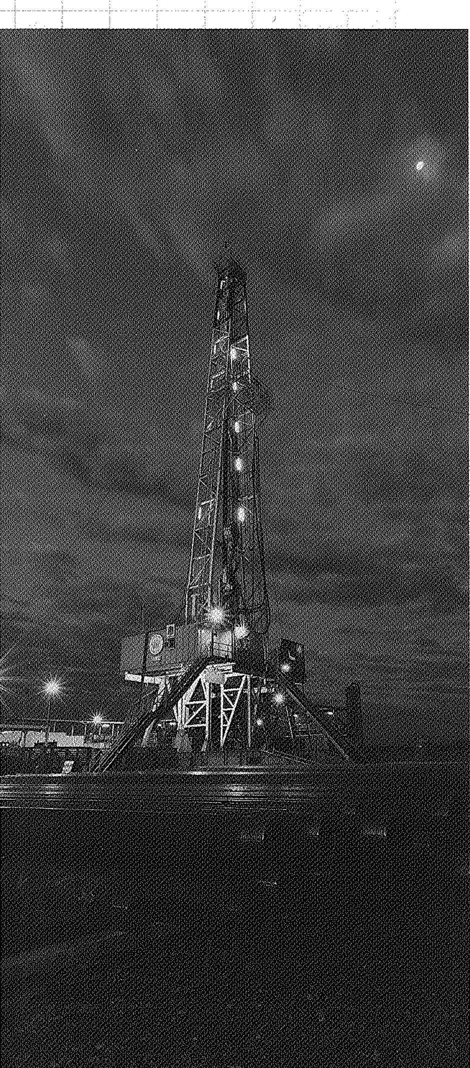
In closing, we look forward to the challenges we face in 2011. Shareholders, management, and employees continue to be aligned and focused on growth in long-term value. We again thank our shareholders for their ownership and our devoted employees for their efforts in 2010. We look forward to 2011 as we continue to strive for the next stacked *interval factor*.

James D. Lightner
Chairman of the Board

H. Craig Clark
President and Chief Executive Officer

Operations

Forest's core areas consist of a well-balanced portfolio of oil, natural gas, and natural gas liquids properties in North America that have exposure to tight-gas sands and shale plays with multiple stacked-pay opportunities. Initial vertical delineation drilling in many of these core areas has established the existence of consistent geologic trends, creating low-risk, repeatable development opportunities. Forest initially exploited the majority of the core operational areas through vertical development, but with the emergence of new drilling and completion technology, the Company has transitioned the development of a number of these plays to horizontal development. Through the application of horizontal drilling, Forest is able to enhance initial production rates and estimated ultimate recoveries while acheiving greater capital efficiency focusing on reducing drilling costs. The primary areas of focus in 2011 will be in the Texas Panhandle, the Western Canadian Sedimentary Basin in Alberta and British Columbia, and the Eagle Ford Shale in South Texas. These core areas will be responsible for Forest's organic growth in 2011 and will consume the majority of the Company's capital expenditures.



Lantern Drilling rig #14

TEXAS PANHANDLE — GRANITE WASH

Forest has approximately 101,000 net acres located in the Texas Panhandle, establishing Forest as one of the top acreage holders in the area. The area provides for excellent horizontal drilling opportunities targeting multiple liquids-rich Granite Wash intervals as well as other multi-pay objectives. Other objectives present in the area include the Douglas, Tonkawa, Cleveland, Atoka, and the Morrow formations. Forest drilled its first horizontal wells in the area in 2009, leveraging its vertical delineation database of over 600 wells to determine the most attractive intervals to initiate a horizontal drilling campaign. Based on results achieved through the 2009 horizontal drilling program, Forest increased its horizontal development rig count from one to five rigs from 2009 to 2010, developing known productive intervals and establishing new prospective intervals for future drilling efforts. During 2010, Forest tested five prospective intervals in the play, establishing a total of eight intervals as prospective for horizontal development. Forest completed 27 horizontal wells in 2010 that had average 24-hour initial production rates of 26 MMcfe/d, of which approximately 57% of the production was in the form of condensate and natural gas liquids. With the favorable price of condensate 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. In 2011, Forest plans to run a six rig drilling program targeting the Granite Wash and other prospective intervals, investing approximately $300 million primarily for the drilling of approximately 40 gross horizontal operated wells.

WESTERN CANADIAN SEDIMENTARY BASIN

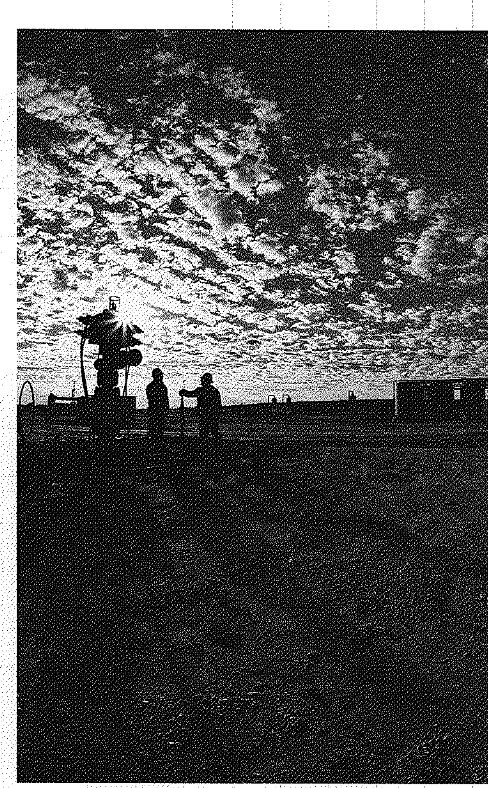
Deep Basin

Forest has approximately 131,000 net acres in the Deep Basin, located in Alberta and British Columbia, Canada, which primarily includes interests in the Narraway/Ojay and Wild River fields. The area provides for a rich geologic setting, with a majority of the play containing a minimum of ten different stacked producing intervals. Forest's vertical delineation program has included the drilling of 15 vertical wells in the Narraway/Ojay fields that had average 24-hour initial production rates of 13 MMcfe/d. With a favorable royalty and tax regime, this play provides superior rates-of-return compared to other natural gas plays in North America. Utilizing zone-specific production data collected from Forest's vertical well database in the Deep Basin, the Company commenced the drilling of its first horizontal well in the Narraway/Ojay fields at the end of the fourth quarter of 2010 and intends to complete this well with multi-stage hydraulic fracturing techniques that have been successfully applied in the Granite Wash area since 2009. Although many of the multi-stacked sand intervals in the Deep Basin have not been exploited horizontally, Forest believes that horizontal drilling will result in improvements in initial production rates and ultimate recoveries. In 2011, Forest plans to run a two rig drilling program in the Narraway/Ojay fields, investing approximately $82 million primarily for the drilling of approximately 15 gross operated wells.

Lantern Drilling rig #17

Peace River Arch

Forest has approximately 41,000 net acres in the Peace River Arch, located in Alberta, Canada, which primarily includes its interests in the Evi light oil field. This area provides for a significant development opportunity for premium-priced light oil through shallow horizontal development drilling. Through December 31, 2010, Forest has drilled 25 horizontal wells in the field. Oil production from this field is light sweet crude providing superior rates-of-return compared to other oil plays in North America. Forest believes that it can ultimately enhance production rates and recoveries in the Evi field through further development drilling and secondary recovery techniques, such as waterflooding. In 2011, Forest plans to run a three rig drilling program in the Evi field, investing approximately $93 million primarily for the drilling of approximately 35 gross operated wells.



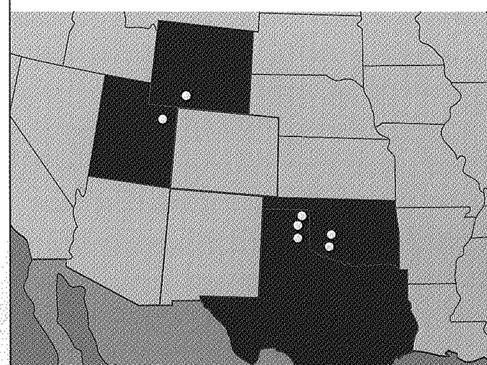
EAGLE FORD SHALE

Forest has approximately 105,000 net acres in the Eagle Ford Shale, located in Gonzales, Wilson, Lee, and DeWitt counties in South Texas. The area provides Forest with access to the oil and liquids rich window of the Eagle Ford Shale and is expected to yield a significant oil development opportunity through the application of horizontal drilling and completion techniques. Forest participated in its first Eagle Ford Shale oil well in the fourth quarter of 2010, as a 50% non-operated partner, that had a 24-hour initial production rate as high as 830 Bbls/d on a restricted 18/64th choke due to limited storage capacity at the well site. After being on-line for 40 days, the well was producing 600 Bbls/d after the installation of tubing and without the benefit of artificial lift. Forest commenced the drilling of its first operated horizontal well in the Eagle Ford oil window at the end of the fourth quarter of 2010 and expanded its initial one rig drilling program to two rigs in the first quarter of 2011. Through Forest's database of vertical penetrations in the Eagle Ford, the Company believes that it can ultimately increase initial production rates and recoveries through the application of horizontal drilling. In 2011, Forest plans to run a two rig drilling program in the Eagle Ford, initially investing approximately $50 million primarily for the drilling of approximately eight gross wells during the first half of 2011. Upon success, Forest would consider expanding this program.

Operational Fact Sheet

Western

	2010	2009	2008
NET PRODUCTION			
Gas (MMcf/d)	77.0	80.2	91.3
Liquids (MBbls/d)	10.0	10.2	11.3
ESTIMATED PROVED RESERVES			
Gas (Bcf)	394.7	362.9	575.0
Liquids (MMBbls)	35.3	27.8	68.9
Equivalent (Bcfe)	606.6	529.9	988.2
DEVELOPED ACREAGE			
Gross	252,679	258,123	384,511
Net	119,918	119,580	230,680
UNDEVELOPED ACREAGE			
Gross	228,340	211,305	416,240
Net	124,033	121,513	272,101
GROSS WELL COUNT			
Gas	972	928	943
Oil	62	66	1,945
CAPITAL EXPENDITURES In thousands			
	$225,659	$147,517	$371,260



2010 HIGHLIGHTS

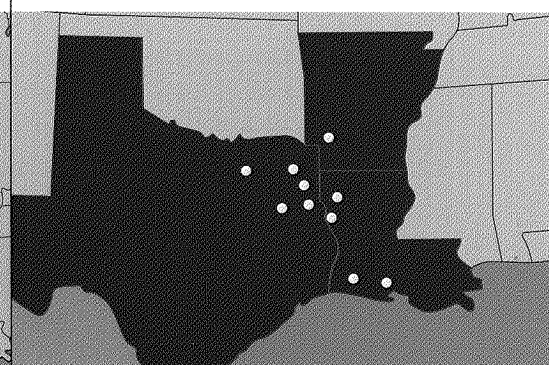
- Increased estimated proved reserves 15%, pro forma for divestitures, to 607 Bcfe at a drill bit reserve replacement ratio of 249%
- Drilled 49 gross wells with a 100% success rate
- 100% horizontal drilling success from 27 gross operated wells in the Texas Panhandle – Granite Wash play with average 24-hour initial production rates of 26 MMcfe/d
- Successfully tested five new intervals in 2010 in the Granite Wash, establishing a total of eight intervals as prospective for horizontal drilling
- Drilled and completed successful Granite Wash horizontal wells over a 30 mile span, expanding the play further north into Hemphill County

2011 STRATEGY

- Drilling program calls for approximately 50 gross wells and a continued high pace of additional projects
- Plan to drill approximately 40 gross operated wells in the Texas Panhandle – Granite Wash play with a six rig drilling program
- Focus horizontal Granite Wash efforts in Wheeler and Hemphill Counties while testing new intervals
- Expand horizontal drilling efforts in other intervals in northwest Hemphill, Lipscomb, and Roberts Counties
- Leverage on the Lantern Drilling rigs as a tool to keep costs in check
- Test new completion techniques to reduce completion costs

Eastern

	2010	2009	2008
NET PRODUCTION			
Gas (MMcf/d)	110.8	123.4	103.4
Liquids (MBbls/d)	3.8	4.8	5.4
ESTIMATED PROVED RESERVES			
Gas (Bcf)	787.1	739.8	727.5
Liquids (MMBbls)	22.1	21.0	24.8
Equivalent (Bcfe)	919.7	866.0	876.1
DEVELOPED ACREAGE			
Gross	226,608	237,903	271,061
Net	164,444	171,520	187,641
UNDEVELOPED ACREAGE			
Gross	106,237	142,729	205,949
Net	66,844	78,578	120,132
GROSS WELL COUNT			
Gas	1,491	1,507	1,421
Oil	232	240	398
CAPITAL EXPENDITURES In thousands			
	$171,540	$206,836	$447,280



2010 HIGHLIGHTS

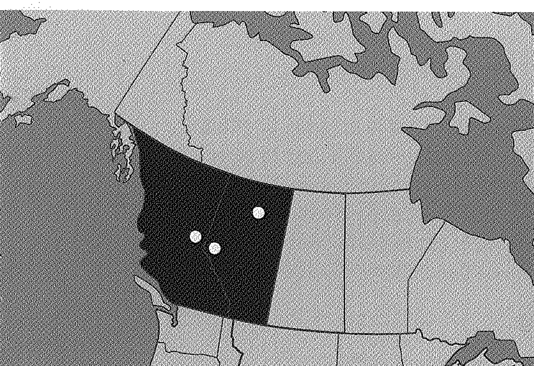
- Increased estimated proved reserves 6%, pro forma for divestitures, to 920 Bcfe at a drill bit reserve replacement ratio of 209%
- Drilled 28 gross wells with an 80% success rate
- Drilled 20 gross horizontal wells in the Haynesville/Bossier Shale in North Louisiana with average 24-hour initial production rates of 16 MMcfe/d
- Instituted restricted flow rate production program from the last six wells in the Haynesville/Bossier Shale drilling program, curtailing production at 11 to 15 MMcfe/d to improve recoveries
- Achieved held-by-production status in the Haynesville/Bossier Shale through 2010 drilling program

2011 STRATEGY

- Drilling program calls for a continued high pace of recompletions targeting high rate-of-return projects
- Focus on liquids plays in East Texas and North Louisiana
- Defer Haynesville/Bossier Shale drilling until either natural gas prices recover or completion costs are reduced
- Leverage on the Lantern Drilling rigs as a tool to keep costs in check
- Test new completion techniques to reduce completion costs

Canada

	2010	2009	2008
NET PRODUCTION			
Gas (MMcf/d)	61.5	63.7	63.7
Liquids (MBbls/d)	2.6	2.3	3.0
ESTIMATED PROVED RESERVES			
Gas (Bcf)	267.0	221.2	237.5
Liquids (MMBbls)	18.3	16.9	8.8
Equivalent (Bcfe)	376.6	322.3	290.5
DEVELOPED ACREAGE			
Gross	218,264	251,120	297,238
Net	148,274	148,246	161,687
UNDEVELOPED ACREAGE			
Gross	888,987	812,021	822,662
Net	642,650	606,951	344,504
GROSS WELL COUNT			
Gas	507	565	668
Oil	317	364	356
CAPITAL EXPENDITURES In thousands			
	$162,611	$74,281	$194,004



2010 HIGHLIGHTS

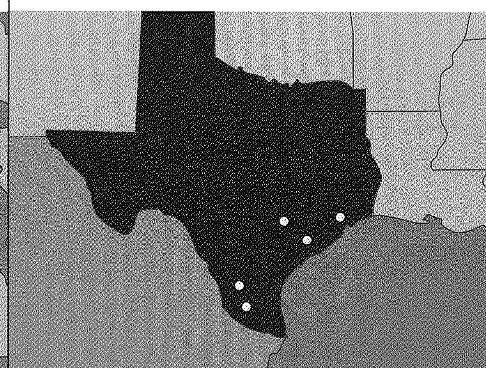
- Increased estimated proved reserves 21%, pro forma for divestitures, to 377 Bcfe at a drill bit reserve replacement ratio of 341%
- Drilled 39 gross wells with a 100% success rate
- Significantly increased net acreage position in the Narraway/Ojay fields
- Since program inception, drilled 15 gross operated wells in the Narraway/Ojay fields with average 24-hour initial production rates of 13 MMcfe/d
- Drilled 14 gross operated wells in the Evi light oil play with average 24-hour initial production rates of 184 Bbls/d
- Initiated first horizontal test in the Narraway field with drilling commencing at the end of the fourth quarter of 2010; first step to transition the play to horizontal development

2011 STRATEGY

- Drilling program calls for approximately 50 gross wells
- Plan to drill approximately 15 gross operated wells in the Narraway/Ojay fields with a two rig drilling program
- Plan to drill approximately 35 gross operated wells in the Evi light oil play with a three rig drilling program
- Continue to test new intervals in the Narraway/Ojay fields through horizontal development
- Test new completion techniques to reduce completion costs

Southern

	2010	2009	2008
NET PRODUCTION			
Gas (MMcf/d)	89.9	114.3	128.0
Liquids (MBbls/d)	2.5	2.6	2.2
ESTIMATED PROVED RESERVES			
Gas (Bcf)	252.0	312.8	417.1
Liquids (MMBbls)	6.3	6.3	6.7
Equivalent (Bcfe)	289.6	350.6	457.0
DEVELOPED ACREAGE			
Gross	174,781	207,309	175,091
Net	109,210	135,092	127,572
UNDEVELOPED ACREAGE			
Gross	118,747	109,848	54,943
Net	109,120	100,805	40,090
GROSS WELL COUNT			
Gas	1,059	1,300	1,268
Oil	67	65	36
CAPITAL EXPENDITURES In thousands			
	$92,083	$74,859	$278,886



2010 HIGHLIGHTS

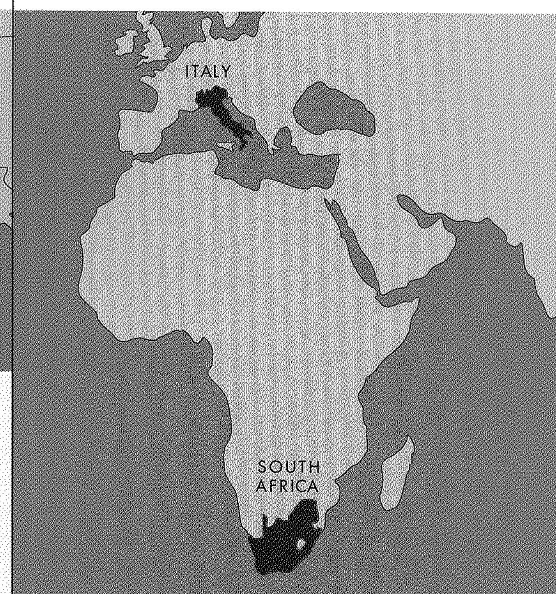
- Estimated proved reserves of 290 Bcfe
- Drilled 22 gross wells with an 88% success rate
- Participated in first Eagle Ford Shale oil well that had a 24-hour initial production rate as high as 830 Bbls/d on a restricted choke; producing 600 Bbls/d after being on production for 40 days
- Initiated first operated horizontal well in the Eagle Ford Shale play with drilling commencing at the end of the fourth quarter of 2010

2011 STRATEGY

- Drilling program calls for approximately 22 gross wells and a continued high pace of additional projects
- Plan to drill approximately eight gross wells in the Eagle Ford Shale play with a two rig drilling program in the first half of 2011
- Expansion of the program in the Eagle Ford Shale play upon further success through initial development program and offset activity
- Leverage on the Lantern Drilling rigs as a tool to keep costs in check
- Test new completion techniques to reduce completion costs

International

	2010	2009	2008
NET PRODUCTION			
Gas (MMcf/d)	–	–	–
Liquids (MBbls/d)	–	–	–
ESTIMATED PROVED RESERVES			
Gas (Bcf)	51.7	51.7	56.3
Liquids (MMBbls)	–	–	–
Equivalent (Bcfe)	51.7	51.7	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	3,060,238
Net	1,705,999	1,705,999	1,762,453
GROSS WELL COUNT			
Gas	2	2	2
Oil	–	–	–
CAPITAL EXPENDITURES In thousands			
	$4,153	$9,186	$6,840



2010 HIGHLIGHTS

- Estimated proved reserves of 52 Bcfe
- Continued progress to commence production from Monte Pallano property in Italy that tested at a combined initial production rate of 22 MMcfe/d without fracture stimulation
- Continued progress to secure gas contracts in South Africa

2011 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, 54
President and
Chief Executive Officer
Years of Service: 10

MICHAEL N. KENNEDY, 36
Executive Vice President
and Chief Financial Officer
Years of Service: 10

JOHN C. RIDENS, 55
Executive Vice President
and Chief Operating Officer
Years of Service: 7

CECIL N. COLWELL, 60
Senior Vice President,
Worldwide Drilling
Years of Service: 22

LEONARD C. GURULE, 54
Senior Vice President,
Western Region
Years of Service: 8

CYRUS D. MARTER IV, 47
Senior Vice President,
General Counsel and Secretary
Years of Service: 9

GLEN J. MIZENKO, 48
Senior Vice President, Business
Development and Engineering
Years of Service: 10

VICTOR A. WIND, 37
Senior Vice President,
Chief Accounting Officer and
Corporate Controller
Years of Service: 6

MARK E. BUSH, 51
Vice President, Eastern Region
Years of Service: 14

RONALD C. NUTT, 53
Vice President, Southern Region
Years of Service: 4

Board of Directors

LOREN K. CARROLL, age 67, 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 CGG-Veritas, a geophysical services and equipment company, and KBR, Inc., an engineering and construction company. Mr. Carroll previously served as a director of Smith International, Inc. and Fleetwood Enterprises, Inc., a producer of recreational vehicles and manufactured homes. Mr. Carroll is a member of our Compensation Committee and is 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 54, 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 60, has been a director since 2000. Mr. Fraser has been President of Sackett Partners Incorporated, a consulting company, and a 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 Subsea 7 S.A., a sub-sea engineering and contracting company. Mr. Fraser previously served as a board member of Smith International, Inc., an oil field service company, and Terra Industries, Inc., a nitrogen-based fertilizer company. Mr. Fraser serves as Chairman of our Audit Committee and is a member of our Nominating and Corporate Governance Committee. Mr. Fraser graduated from Princeton University with a bachelor of arts degree.

JAMES D. LIGHTNER, age 58, has been a director since 2004 and has served as our non-executive Chairman of the Board since May 2008. Mr. Lightner has been the 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.

JAMES H. LEE, age 62, has been a director since 1991. Mr. Lee has served as the Managing General Partner of Lee, Hite & Wisda Ltd., an oil and gas consulting and exploration firm, since 1984. Mr. Lee 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.

PATRICK R. MCDONALD, age 53, 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, Inc. where he was responsible for oil and gas exploration efforts in the Middle and Far East. 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 65, 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, 2010

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 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, 2010, the last business day of the registrant's most recently completed second fiscal quarter, was $3,071,420,932 (based on the closing price of such stock).

There were 113,610,016 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 17, 2011.

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, 2010 are incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1. Business.

General

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, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). 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" for the definition of certain terms.

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 oil and gas reserves as of December 31, 2010 were approximately 2,244 Bcfe. At December 31, 2010, approximately 81% of Forest's estimated proved oil and gas reserves were in the United States, approximately 17% were in Canada, and approximately 2% were in Italy.

In December 2010, we announced our intention to separate our Canadian operations through an initial public offering ("IPO") of up to 19.9% of the common stock of our wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which will be the holding company of the Canadian operations, followed by a distribution of the remaining shares of Lone Pine held by us to our shareholders. The proceeds from the IPO will be used to repay intercompany debt owed to Forest, and the remainder, if any, for general corporate purposes. We expect the IPO to occur in the first half of 2011 and the spin-off of the remaining shares of Lone Pine to occur approximately four months after the IPO; however, we will retain the right to decide whether to commence the spin-off at our discretion. See Part I, Item 1A—"Risk Factors—*We may be unable to complete the separation of our Canadian operations as planned or on the terms and manner currently contemplated, and any completed separation may have a negative impact on our business operations, results of operations and financial condition.*"

Strategy

Our business strategy is to increase shareholder value by efficiently increasing production and reserves by exploiting our significant and diversified undeveloped acreage positions. We expect to execute this strategy, while managing our debt levels relative to our estimated proved reserves and EBITDA, by keeping our exploration and development expenditures at or near cash flows provided by operating activities. We endeavor to execute this strategy as follows:

Exploit and develop resource plays by applying horizontal drilling. We plan to continue to apply the latest technologies to our resource plays, including horizontal drilling and multi-stage hydraulic fracture stimulation techniques. We believe these technologies provide for efficient production and reserve growth from our diverse portfolio of undeveloped oil and gas acreage positions. Our core operational areas, which are discussed in more detail below, have a large number of remaining commodity-diverse drilling locations, providing for what we believe to be repeatable development opportunities. In 2011, we intend to devote approximately 85% of our capital expenditures to our core areas, including approximately 50% in the Texas Panhandle where liquids-rich Granite Wash intervals are targeted.

Enhance returns by focusing on operational control, cost efficiencies and high-margin projects. Our development efforts are focused in areas where we have concentrated land positions, large drilling inventory, and operational control, which allow us to reduce costs. Furthermore, our commodity-diverse portfolio allows us to allocate capital to projects with the highest margins, which currently include oil or liquids-rich drilling prospects. Our concentrated land positions, operational control, and focus on cost and margin allow us to achieve economies of scale and provide for higher rates of return on invested capital.

Develop, expand, and rationalize our asset base through leasehold and property acquisitions, divestitures, and exploration. We intend to pursue leasehold and property acquisitions to enhance existing business operations in our core areas with a preference for liquids-rich hydrocarbon prospects. We also plan to pursue a measured exploration drilling program in these areas to expand the ultimate scope of commercial development of our asset base. As economic conditions permit, we intend to divest assets that do not fit our primary business strategy, including those without significant development opportunities.

Maintain financial flexibility. We expect to maintain a strong liquidity position to successfully execute our growth strategy through the application of budget controls and prudent financial management. We intend to focus on managing our debt levels relative to our estimated proved reserves and EBITDA.

Core Operational Areas

Forest's core areas consist of a well-balanced portfolio of oil, natural gas, and natural gas liquids properties in North America that have exposure to tight-gas sands and shale plays with multiple stacked-pay opportunities. Initial vertical delineation drilling in many of our core areas has established the existence of consistent geologic trends, creating what we believe to be low-risk, repeatable development opportunities. Forest initially exploited the majority of its core operational areas through vertical development, but with the emergence of new drilling and completion technology, Forest has transitioned the development of a number of these plays 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 drilling costs. Our primary areas of focus in 2011 will be in the Texas Panhandle, the Western Canadian Sedimentary Basin in Alberta and British Columbia, Canada, and the Eagle Ford Shale in South Texas. We expect that these core areas will be primarily responsible for Forest's organic growth in 2011 and will consume the majority of the Company's capital expenditures.

Texas Panhandle—Granite Wash

We have approximately 101,000 net acres in the Granite Wash, located in the Texas Panhandle, establishing Forest as one of the top acreage holders in the area. The area provides for excellent horizontal drilling opportunities targeting multiple liquids-rich Granite Wash intervals as well as other multi-pay objectives. Other objectives present in the area are the Douglas, Tonkawa, Cleveland, Atoka, Novi-Lime, and the Morrow. We drilled our first horizontal wells in the area in 2009, leveraging our vertical delineation database of over 600 wells to determine the most attractive intervals to initiate a horizontal drilling campaign. Based on significant results achieved through the 2009 horizontal drilling program, Forest increased its horizontal development rig count from one to five rigs from 2009 to 2010, developing known productive intervals and establishing new prospective intervals for future drilling efforts. During 2010, Forest tested five prospective intervals in the play, establishing a total of eight intervals as prospective for horizontal development. Forest completed 27 horizontal wells in 2010 that had average 24-hour initial production rates of 26 MMcfe/d, of which approximately 57% of the production was in the form of condensate and natural gas liquids. With the favorable price of condensate 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. In 2011, we plan to run a six rig drilling program targeting the Granite Wash and other prospective intervals, investing approximately $300 million primarily for the drilling of approximately 40 gross horizontal operated wells.

Western Canadian Sedimentary Basin

Deep Basin

We have approximately 131,000 net acres in the Deep Basin, located in Alberta and British Columbia, Canada, which primarily includes our interests in the Narraway/Ojay and Wild River fields. The area provides for a rich geologic setting, with a majority of the play containing a minimum of ten different stacked producing intervals. Forest's vertical delineation program has included the drilling of 15 vertical wells in the Narraway/Ojay fields that had average 24-hour initial production rates of 13 MMcfe/d. With a favorable royalty and tax regime, this play provides superior rates of return compared to similar natural gas plays in North America. Utilizing zone-specific production data collected from our vertical well database in the Deep Basin, we commenced the drilling of our first horizontal well in the Narraway/Ojay fields at the end of the fourth quarter of 2010 and intend to complete this well with multi-stage hydraulic fracturing techniques that have been successfully applied in the Granite Wash area since 2009. Although many of the multi-stacked sand intervals in the Deep Basin have not been exploited horizontally, we believe that horizontal drilling will result in improvements in initial production rates and ultimate recoveries. In 2011, we plan to run a two rig drilling program in the Narraway/Ojay fields, investing approximately $82 million primarily for the drilling of approximately 15 gross wells.

Peace River Arch

We have approximately 41,000 net acres in the Peace River Arch, located in Alberta, Canada, which primarily includes our interests in the Evi light oil field. This area provides for a significant development opportunity for premium-priced light oil through shallow horizontal development drilling opportunities. Through December 31, 2010, Forest drilled 25 horizontal wells. Oil production from this field is light sweet crude providing superior rates of return compared to other oil plays in North America. We believe that we can ultimately enhance production rates and recoveries in the Evi field through further development drilling and secondary recovery techniques, such as waterflooding. In 2011, we plan to run a three rig drilling program in the Evi field, investing approximately $93 million primarily for the drilling of approximately 35 gross wells.

South Texas—Eagle Ford Shale

We have approximately 105,000 net acres in the Eagle Ford Shale, located in Gonzales, Wilson, Lee, and DeWitt counties in South Texas. The area provides Forest with access to the oil-bearing section of the Eagle Ford and is expected to yield a significant oil development opportunity through the application of horizontal drilling and completion technologies. We commenced the drilling of our first horizontal well in the Eagle Ford oil window at the end of the fourth quarter of 2010 and expanded our initial one rig drilling program to two rigs in the first quarter of 2011. Through Forest's database of vertical penetrations in the Eagle Ford, we believe that we can ultimately increase initial production rates and recoveries through the application of horizontal drilling. In 2011, we plan to run a two rig drilling program in the Eagle Ford, initially investing approximately $50 million primarily for the drilling of approximately eight gross wells during the first half of 2011. Upon success, Forest would consider expanding this program.

East Texas / North Louisiana—Haynesville/Bossier Shale

We have approximately 169,000 net acres in the East Texas / North Louisiana area. The area provides for excellent horizontal and vertical drilling opportunities targeting multiple stacked-pay intervals, including the Cotton Valley, Haynesville, Bossier, and other formations. In 2010, our development program was focused in the Haynesville/Bossier Shale in North Louisiana where we drilled 20 horizontal wells that had average initial 24-hour production rates of 16 MMcfe/d. In an effort to optimize recovery from Haynesville/Bossier Shale wells, Forest instituted a restricted flow rate production program. Under this program, initial production rates from the last six wells were curtailed at 11 to 15 MMcfe/d. Results have indicated that cumulative production from restricted rate wells exceeded the cumulative production from comparable unrestricted wells at a period of approximately 90 days. In 2011, as our acreage base is now generally held-by-production, we plan to redirect our capital spending in this area to more liquids-rich plays in our other core areas until either natural gas prices recover or drilling and completion costs are reduced.

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 Texas Panhandle 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. As of the closing date of the acquisition, the assets included approximately 350 Bcfe of estimated proved reserves and 85,000 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, 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 approximately $726 million.

Divestitures

In 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 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, 2010, based on the Henry Hub price of $4.38 per MMBtu for natural gas and the West Texas Intermediate price of $79.81 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, 2010. See—"*Preparation of Reserves Estimates*" below and Note 16 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)[1]
Developed:			
United States	886,644	37,541	1,111,890
Canada	169,292	6,594	208,856
Italy	25,869	—	25,869
Total developed	1,081,805	44,135	1,346,615
Undeveloped:			
United States	547,087	26,161	704,053
Canada	97,721	11,666	167,717
Italy	25,869	—	25,869
Total undeveloped	670,677	37,827	897,639
Total estimated proved reserves	1,752,482	81,962	2,244,254

(1) Oil and natural gas liquids are converted to gas-equivalents using a conversion of six Mcf "equivalent" per barrel of oil or natural gas liquids. This conversion is based on energy equivalence and not price equivalence. For 2010, the average of the first-day-of-the-month gas price was $4.38 per Mcf, and the average of the first-day-of-the-month oil price was $79.81 per barrel. If a price-equivalent conversion based on these twelve-month average prices was used, the conversion factor would be approximately 18 Mcf per barrel of oil or NGL rather than 6 Mcf per barrel of oil or NGL.

As of December 31, 2010, Forest had estimated proved reserves of 2,244 Bcfe, an increase of 6% compared to 2,121 Bcfe at December 31, 2009. Of that total, 1,816 Bcfe (81%) were in the United States, 377 Bcfe (17%) were in Canada, and 52 Bcfe (2%) were in Italy. During 2010, we added 384 Bcfe of estimated proved reserves through extensions and discoveries primarily driven by our 2010 drilling activity in the Texas Panhandle, North Louisiana, and the Western Canadian Sedimentary Basin, which were offset by property sales of 62 Bcfe and negative revisions of 39 Bcfe.

As of December 31, 2010, proved undeveloped reserves ("PUDs") were estimated to be 898 Bcfe, or 40% of estimated proved reserves, compared to 791 Bcfe, or 37% of estimated proved reserves as of December 31, 2009. The net increase of 106 Bcfe was primarily due to the recording of PUD locations offset to our horizontal and vertical producing wells in the Texas Panhandle and the Deep Basin in Canada. We invested $174 million to convert 91 Bcfe of our December 31, 2009 PUD reserves to proved developed reserves during 2010. We intend to convert the PUDs disclosed as of December 31, 2010 to proved developed reserves within five years of the date they were initially disclosed as PUDs.

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" rule, which was 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 the reporting date, 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.

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 (i) the unweighted arithmetic average first-day-of-the-month prices during the twelve-month period prior to December 31, 2010 as required by SEC regulations and (ii) an alternative price using the NYMEX five-year future strip price as of December 31, 2010. Forest presents the pre-tax PV-10 value, which is not a financial measure accepted under Generally Accepted Accounting Principles ("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	Five-Year NYMEX Strip Price
Henry Hub natural gas price	$ 4.38	$ 5.25
West Texas Intermediate oil price	79.81	93.08
Pre-tax PV-10 value (in millions)	$3,273	$4,435
Less: Income tax effects discounted at 10% per annum (in millions)	554	950
Standardized measure of discounted future net cash flows (in millions)	$2,719	$3,485

Preparation of Reserves Estimates

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 at least 80% of our proved reserves, based on net present value, are 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 in excess of 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 us in early 2001. Prior to joining Forest, 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 has been a member of the Society of Petroleum Engineers for over twenty-five years.

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," below for a description of some of the risks and uncertainties associated with our business and reserves.

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 5% of the independent reserve engineers' quantity estimates on a Company basis and within 10% 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, 2010, 2009, and 2008, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the year ended December 31, 2010, DeGolyer and MacNaughton independently audited estimates relating to properties constituting over 87% of our reserves by NPV as of December 31, 2010. When compared on a field-by-field basis, some of Forest's estimates of proved reserves were greater and some were less than the estimates prepared by DeGolyer and MacNaughton. However, in the aggregate, Forest's estimates of total proved reserves were within 5% 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

The following table summarizes the number of wells drilled during 2010, 2009, and 2008, 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, 2010, we had 14 gross (6 net) wells in progress in the United States and 2 gross (1 net) wells in progress in Canada. During 2010, we drilled a total of

148 gross (89 net) wells, of which 29 were classified as exploratory and 119 were classified as development. Our 2010 drilling program achieved a 93% success rate.

	Year Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
United States						
Productive	75	38	76	47	550	323
Non-productive(1)	5	4	6	4	15	11
Total	80	42	82	51	565	334
Canada						
Productive	39	27	7	3	64	39
Non-productive(1)	—	—	—	—	—	—
Total	39	27	7	3	64	39
Total development wells	119	69	89	54	629	373
Exploratory wells:						
United States						
Productive	24	16	23	14	72	54
Non-productive(1)	5	4	—	—	3	2
Total	29	20	23	14	75	56
Canada						
Productive	—	—	4	2	10	8
Non-productive(1)	—	—	—	—	—	—
Total	—	—	4	2	10	8
Italy						
Productive	—	—	—	—	—	—
Non-productive(1)	—	—	1	1	—	—
Total	—	—	1	1	—	—
Total exploratory wells	29	20	28	17	85	64

(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

The following table summarizes our productive wells as of December 31, 2010, all of which are located in the United States, Canada, and Italy. 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, 2010, Forest owned interests in 347 gross wells containing multiple completions.

	United States		Canada		Italy		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gas	3,522	2,602	507	338	2	2	4,031	2,942
Oil	361	212	317	258	—	—	678	470
Total	3,883	2,814	824	596	2	2	4,709	3,412

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, 2010. 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, 2010, approximately 19%, 10%, and 5% of our net undeveloped acreage in the United States and Canada was held under leases that will expire in 2011, 2012, and 2013, respectively, if not extended by exploration or production activities. Approximately 40% of the acres expiring in 2011 are held under leases that can be extended, at our option, for another two years.

	Developed Acreage		Undeveloped Acreage	
Location	**Gross**	**Net**	**Gross**	**Net**
United States:				
Western[(1)]	252,679	119,918	228,340	124,033
Eastern[(2)]	226,608	164,444	106,237	66,844
Southern[(3)]	174,781	109,210	118,747	109,120
	654,068	393,572	453,324	299,997
Canada[(4)]	218,264	148,274	888,987	642,650
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	874,832	544,096	4,402,549	2,648,646

(1) The Western Business Unit's acreage is primarily located in the Texas Panhandle and the Uintah field in Utah.

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

(3) The Southern Business Unit's acreage is primarily located in South Texas, including approximately 105,000 net acres prospective for the Eagle Ford shale in Gonzales, Wilson, Lee, and DeWitt counties.

(4) The Canadian Business Unit's acreage is primarily located in the Deep Basin area in Alberta and British Columbia, the Peace River Arch area in Alberta, and 274,000 net acres in Quebec prospective for the Utica Shale.

(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 was executed in April 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, 2010, 2009, and 2008 by geographical area. Forest's Italian geographical area has not had any production and Forest does not have any fields that individually contain 15% or more of the Company's total estimated proved reserves.

	United States			Canada			Total Company		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Natural Gas:									
Production volumes (MMcf)	101,346	116,029	118,120	22,436	23,248	23,313	123,782	139,277	141,433
Average sales price (per Mcf)	$ 3.99	$ 3.33	$ 7.54	$ 3.71	$ 3.15	$ 6.98	$ 3.94	$ 3.30	$ 7.45
Liquids:									
Oil and condensate:									
Production volumes (MBbls)	2,357	3,397	3,778	828	626	802	3,185	4,023	4,580
Average sales price (per Bbl)	$ 76.08	$ 56.87	$ 96.85	$ 67.51	$ 51.14	$ 86.68	$ 73.85	$ 55.98	$ 95.07
Natural gas liquids:									
Production volumes (MBbls)	3,589	3,012	3,151	134	230	300	3,723	3,242	3,451
Average sales price (per Bbl)	$ 34.54	$ 25.17	$ 44.54	$ 51.68	$ 30.82	$ 60.71	$ 35.16	$ 25.57	$ 45.94
Total liquids:									
Production volumes (MBbls)	5,946	6,409	6,929	962	856	1,102	6,908	7,265	8,031
Average sales price (per Bbl)	$ 51.01	$ 41.97	$ 73.06	$ 65.30	$ 45.68	$ 79.61	$ 53.00	$ 42.41	$ 73.96
Total production volumes (MMcfe)	**137,022**	**154,483**	**159,694**	**28,208**	**28,384**	**29,925**	**165,230**	**182,867**	**189,619**
Average sales price (per Mcfe)	**$ 5.16**	**$ 4.24**	**$ 8.75**	**$ 5.18**	**$ 3.95**	**$ 8.37**	**$ 5.17**	**$ 4.20**	**$ 8.69**
Production costs (per Mcfe):									
Lease operating expenses	$ .67	$ .77	$ .83	$ .91	$ .97	$ 1.21	$ .71	$ .80	$ .89
Transportation and processing costs	.10	.08	.06	.38	.28	.32	.15	.11	.10
Production costs excluding production and property taxes (per Mcfe)	.77	.86	.89	1.29	1.25	1.53	.86	.92	.99
Production and property taxes	.32	.26	.49	.09	.10	.12	.28	.23	.43
Total production costs (per Mcfe)	**$ 1.09**	**$ 1.12**	**$ 1.38**	**$ 1.38**	**$ 1.35**	**$ 1.65**	**$ 1.14**	**$ 1.15**	**$ 1.42**

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. As of February 17, 2011, we have a delivery commitment of approximately 21 Bbtu/d of natural gas, which provides for a price equal to NYMEX Henry Hub less $1.49 to a buyer through October 31, 2014, unless the Henry Hub price exceeds $6.50 per MMBtu, at which point we share the amount of the excess equally with the buyer. Approximately 90% of our current natural gas production in Alberta and British Columbia is available to be used as source gas for this delivery commitment. Based on our estimated proved reserves as of December 31, 2010, approximately 72 MMcfe/d, 64 MMcfe/d, and 74 MMcfe/d will be available as source gas from these fields in 2011, 2012, and 2013, respectively.

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. Each of the jurisdictions in which we own or operate producing crude oil and natural gas properties has 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 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 amended 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 million per day per violation. The 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 believe these rules affect us 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.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was enacted which, among other things, imposes new reporting and other requirements on our business and operations, including with respect to payments made to U.S. and foreign governments related to our oil and gas exploration and development activities. The legislation also imposes new requirements and oversight on our derivatives transactions, including potential new clearing, margin, and position limits requirements. Significant regulations are required to be promulgated by the SEC and the Commodity Futures Trading Commission to implement these requirements and provide certain exemptions for qualified end-users. Although Forest does not anticipate it will be affected differently than other producers of oil and natural gas, the new requirements are likely to impose additional reporting obligations on us with respect to the use of derivative instruments to hedge against commercial risks related to fluctuations in oil and gas commodity prices and interest rates. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future. The imposition of these types of requirements or limitations could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activities.

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 us in a manner significantly different from other oil and natural gas companies 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 us 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 royalty framework (since named the Alberta Royalty Framework, or ARF) established 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 ARF, as further amended, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependent on the market price and production volumes. Royalty rates for conventional oil range from 0% to 40%. Natural gas royalty rates range from 5% to 36%.

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), for which drilling begins between November 19, 2008 and December 31, 2013 (since changed to December 31, 2010), would have a one-time option of selecting transitional royalty rates or ARF rates. The transition option provides for lower royalties in the initial years of a well's life and at some commodity price points. 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 will revert to ARF 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. The Deep Oil Exploration Program, or DOEP, and the Natural Gas Deep Drilling Program, or NGDDP, provide upfront royalty adjustments to qualifying new wells. To qualify for royalty adjustments under the DOEP, exploration wells must have a true vertical depth greater than 2,000 meters (6,562 feet) and drilling must commence on or after January 1, 2009. Oil wells in this category qualify for a royalty exemption on either the first $1 million (Canadian dollars) of royalty or the first 12 months of production. The DOEP is a five year program. No wells drilled after December 31, 2013 will qualify for benefits under the DOEP, and no royalty adjustments will be granted under the DOEP after December 31, 2018. The

NGDDP, as revised effective May 1, 2010, applies to qualifying exploration and development gas wells producing at a true vertical depth greater than 2,000 meters (6,562 feet) for which drilling commenced on or after May 1, 2010. The NGDDP provides for an escalating royalty credit in line with progressively deeper wells from $625 (Canadian dollars) per meter ($191 (Canadian dollars) per foot) to a maximum of $3,750 (Canadian dollars) per meter ($1,143 (Canadian dollars) per foot). A minimum 5% royalty will apply to these gas wells. 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 included a Drilling Royalty Credit, or DRC, for new oil, natural gas and non-project oil sands wells for which drilling commenced and finished between April 1, 2009 and March 31, 2011, and a New Well Royalty Rate, or NWRR, for wells that began producing between April 1, 2009 and March 31, 2010. The DRC provides for a royalty credit of up to $200 (Canadian) per meter ($61 (Canadian) per foot) drilled in respect of qualifying wells with certain annual limitations on the amount of annual credits received directly from the Alberta Government. The NWRR provides for a maximum 5% royalty rate for the first twelve months of production to a maximum of 50,000 barrels of oil or 500 MMcf of natural gas.

On March 11, 2010, the Alberta Government announced its intention to adjust the royalty framework established in January 2009, which adjustments became effective January 1, 2011 and reduced the maximum ARF royalty rates to 40% for conventional oil and to 36% for natural gas (previously 50% for both conventional oil and natural gas). In addition, the Alberta Government made the incentive 5% royalty rate on new natural gas and conventional oil wells under the NWRR a permanent feature of the royalty system subject to the same 12-month time and maximum volume limits. The transitional royalty framework announced in November 2008 was also amended. Transitional royalty rates for qualifying wells will continue until December 31, 2013 as originally announced, but the one-time option of selecting transitional royalty rates ended on December 31, 2010 and, effective January 1, 2011, no new wells are allowed to select transitional royalty rates.

On May 27, 2010, the Alberta Government announced a number of additional programs for qualifying wells coming on production after May 1, 2010. One such program, the Shale Gas New Well Royalty Rate, extended the 5% NWRR on qualifying shale gas wells from 12 months to 36 months and removed the 500 MMcf volume limit. Similarly, the Coalbed Methane New Royalty Rate extended the 5% NWRR on qualifying coalbed methane wells from 12 months to 36 months and increased the 500 MMcf volume limit to 750 MMcf. The Horizontal Gas New Royalty Rate extended the 5% NWRR on qualifying horizontal gas wells from 12 months to 18 months. Finally, the Horizontal Oil New Royalty Rate extended the 5% NWRR on qualifying horizontal oil wells from 12 months to a minimum of 18 months and increased producing time and volume limits according to the measured depth of the well's qualifying interval to a maximum of 48 months or 100,000 bbls, respectively.

Environmental

We are subject to stringent national, state, provincial, and local laws and regulations in the jurisdictions where we operate relating to environmental protection, including the manner in which various substances such as 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 additional compliance costs, 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 closures 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 emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"). At the Copenhagen Conference in 2009, government leaders and representatives from approximately 170 countries met to negotiate a successor to the Kyoto Protocol, which expires in 2012. The primary result of the Copenhagen Conference was the Copenhagen Accord, which is not a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the Kyoto Protocol's commitment to reducing GHG emissions and promises funding to help developing countries mitigate and adapt to climate change. Canada has committed under the Copenhagen Accord to reducing its GHG emissions by 17% from 2005 levels by 2020, but the Copenhagen Accord does not establish binding GHG emissions reduction targets. The United States has not ratified the Kyoto Protocol or the Copenhagen Accord.

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. Regulations to implement the Regulatory Framework had been expected, but the federal government has delayed their release, and potential federal requirements in respect of GHG emissions are unclear. On January 30, 2010, the Canadian federal government announced its new GHG emissions reduction of 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020. 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. 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 takes place at the provincial and municipal levels in Canada. 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, applies to facilities in Alberta that have produced 100,000 or more tons of GHG emissions in 2003 or any subsequent year, and requires mandatory emissions reductions through the use of emissions intensity targets. 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 (Canadian dollars) per ton of GHG emissions to the Alberta Climate Change and Management Fund. The Specified Gas Reporting Regulation also imposes GHG emissions reporting requirements. Alberta Environment has publicly announced its intention to lower this reporting threshold for facilities to 50,000 tons of GHG emissions annually. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations in permits and under other environmental regulations. The Province of Alberta announced in January 2008 a new climate change plan setting out a goal of achieving a 14% absolute reduction in GHG emissions below 2005 levels in the province by 2050. 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.

Nearly half of the states in the U.S., 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, and subsequently in December 2009, the United States Environmental Protection Agency ("EPA") determined 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.

On November 8, 2010, the EPA finalized GHG reporting requirements for the petroleum and natural gas industries. Under this final rule, owners or operators of facilities that contain petroleum and natural gas systems, as defined by the rule, and emit 25,000 metric tons or more of GHGs per year (expressed as carbon dioxide equivalents) will report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. Owners or operators will collect emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, record keeping, and reporting defined in the final rule. For purposes of the rule, an onshore petroleum and natural gas production facility is generally defined as all petroleum and natural gas equipment associated with all petroleum or natural gas production wells and CO2 enhanced oil recovery operations that are under common ownership or control, including leased, rented, and contracted activities, by an onshore petroleum and natural gas production owner or operator and that are located within a single hydrocarbon basin as defined by the American Association of Petroleum Geologists. The rule is estimated to require reporting from approximately 2,800 facilities, covering 85 percent of the total GHG emissions from the U.S. petroleum and natural gas industries, including all of Forest's facilities. We expect these new rules to result in increased compliance costs on our operations. In addition, these rules, and any other new rules and regulations addressing GHG emissions, could result in additional operating restrictions.

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, 2010, we had 681 employees. None of our employees is currently represented by a union for collective bargaining purposes.

Geographical Data

Forest operates in one industry segment. For information relating to our geographical operating segments, see Note 14 to the Consolidated Financial Statements of this 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 ensure that production from our properties, if obtained, will be salable by 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 or British Thermal Unit. 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.

Hydraulic fracturing. A process used to stimulate production of hydrocarbons. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.

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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. 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 property taxes, future capital costs, operating expenses, and estimated future income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC's requirements, 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 in accordance with the SEC's regulations and are held constant for the life of the reserves.

Undeveloped Acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of 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 and Section 21E of the Exchange Act. 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.

We may be unable to complete the separation of our Canadian operations as planned or on the terms and manner currently contemplated, and any completed separation may have a negative impact on our business operations, results of operations and financial condition.

In December 2010, we announced a strategy to separate our Canadian operations through an initial public offering (the "IPO") of up to 19.9% of the common stock of our wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which will be the holding company of the Canadian operations, followed by a distribution of the remaining shares of Lone Pine held by us to our shareholders. The completion of the IPO and subsequent spin-off of Lone Pine are subject to various risks, including market conditions, which are beyond Forest's control. These risks could have a negative impact on our business operations, results of operations, or financial condition, including:

- the distraction of management and disruption of operations;
- the process of completing the separation may be time consuming and expensive and may result in the loss of business opportunities; and
- our inability to achieve the expected benefits of the IPO, the spin-off, or both.

It is possible that the IPO or the spin-off, or both, will not be completed. Furthermore, if the IPO is completed but the spin-off is not, our securities and other compliance obligations, including associated costs, will increase significantly as Lone Pine will have independent reporting and corporate governance requirements, but will remain a part of our consolidated group.

Our announcement of Lone Pine's initial public offering did not, and this report does not, constitute an offer to sell or the solicitation of an offer to buy any securities. Any offers, solicitations of offers to buy, or any sales of securities of Lone Pine will be made only in accordance with the registration requirements of the Securities Act or an exemption therefrom.

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, results of operations, 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 and natural gas spot prices are significantly lower than their historical, or near historical, highs reached in 2008, and prices 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 sources of energy;
- 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 78% of our estimated proved reserves at December 31, 2010 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. In addition, as noted above, the amount available for borrowing under our bank credit facilities is adjusted based on periodic determinations of our estimated proved reserves, which may be reduced in the event of commodity price declines. 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.

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 the IPO or the Lone Pine spin-off, 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 anticipated 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 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 U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of legislation.

The Fiscal Year 2012 U.S. Budget proposed by the President recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies, and legislation has been introduced in Congress that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of such U.S. federal income tax incentives. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could impact the rate at which we develop our oil and gas properties.

The enactment of financial reform legislation could have an adverse impact on our ability to hedge risks associated with our business.

On July 21, 2010, the Dodd-Frank Act was enacted, which will, among other things, impose new requirements and oversight on derivatives transactions, including new clearing and margin requirements. Significant regulations are required to be promulgated by the SEC and the Commodity Futures Trading Commission to implement these requirements and provide certain exemptions for qualified end-users. The new requirements, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in oil and gas commodity prices and interest rates, and could have an adverse effect on our ability to effectively hedge risks associated with our business.

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 and audited by DeGolyer and MacNaughton, an independent petroleum engineering firm. 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 estimated 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 estimated 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, 2010, approximately 40% 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 estimated 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 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 other 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, may be less leveraged than we are and have a lower cost of capital. 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 may depend 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 regulatory developments. For instance, Canadian federal and provincial governments have announced initiatives to reduce greenhouse gas emissions, and regulations to implement such initiatives could potentially impact our operations. See Part I, "Business-Regulation-*Canada*" and "Business-Regulation-*Environmental*" 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 our being unable 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 the Utica Shale 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 may 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.

Many of the laws and regulations to which our operations are subject include those relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and the clean-up of contaminated sites. We could incur material costs, including clean-up costs, fines and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, environmental laws and regulations. Such laws and regulations not only expose us to liability for our own activities, but may also expose us to liability for the conduct of others or for actions by us that were in compliance with all applicable laws at the time those actions were taken. In addition, we could incur substantial expenditures complying with environmental laws and regulations, including future environmental laws and regulations which may be more stringent, for example, the regulation of GHG emissions under new federal legislation, the federal Clean Air Act, or state or regional regulatory programs. Regulation of GHG emissions by Congress, the EPA, or various other legislative or regulatory bodies in the United States, Canada or Italy could have an adverse effect on our operations and demand for the oil and natural gas that we produce. See Part I, Item 1, "Business—Regulation" for more 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.

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 have 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. For example, Forest has been joined as a defendant in a dispute over which companies should bear the cost of decommissioning and abandoning the "Spurr Platform" and its associated wells, located in Cook Inlet, Alaska. See Part I, Item 3—"Legal Proceedings" for a discussion of material litigation involving the Alaska Assets. In addition, PERL has asserted during its bankruptcy case that the Alaska Assets were worth less than what PERL paid for them in August 2007, and that Forest may face liability under creditors' rights laws or other laws in connection with the transaction. Forest disagrees with both the working interest owners' assertion and PERL's assertion and, to the extent necessary, will vigorously oppose any efforts to hold Forest liable for PERL's unsatisfied obligations or for the sale of the Alaska Assets to PERL. We cannot predict, however, whether we would be successful in avoiding all such liabilities.

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.

Item 1B. Unresolved Staff Comments.

As of December 31, 2010, 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.

In August 2007, Forest sold all of its Alaska assets to Pacific Energy Resources Ltd. and its related entities ("PERL"). On March 9, 2009, PERL filed for bankruptcy. As part of the plan of liquidation of its bankruptcy, PERL "abandoned" its interests in many of the Alaska assets sold to it by Forest, including the Trading Bay Unit and Trading Bay Field ("Trading Bay"). At the time of the abandonment of PERL's interests in Trading Bay, Union Oil Company of California ("Unocal") was the operator of those assets. On December 2, 2010, Unocal filed a lawsuit styled *Union Oil Company of California v. Forest Oil Corporation* in Anchorage District Court, Alaska. Forest has removed the case to federal district court in Anchorage, Alaska. In the lawsuit, Unocal complains about PERL's abandonment of Trading Bay and states that PERL has failed to pay approximately $48 million in joint interest billings owed on those properties to date. Unocal further claims that Forest is liable for PERL's share of all joint interest billings owed on Trading Bay, in arrears and in the future, because (1) Forest was the predecessor party to the contracts governing the operations at Trading Bay, (2) Unocal did not agree that, in conjunction with Forest's sale of its Alaska assets, Forest would be released of its obligations under the Trading Bay contracts, and (3) PERL has defaulted on the joint interest billings owed on Trading Bay since October 2008. Although we are unable to predict the final outcome of this case, we believe that the allegations of this lawsuit are without merit, and we intend to vigorously defend the action.

We are a party to various other 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.

Item 4. Removed and Reserved.

Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of February 17, 2011.

Name	Age	Years with Forest	Office[1]
H. Craig Clark	54	10	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	36	10	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	55	7	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 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	60	22	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	54	8	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	47	9	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 in the law firm of Susman Godfrey L.L.P. in Houston, Texas.
Glen J. Mizenko	48	10	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	37	6	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	50	14	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	53	4	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 17, 2011, our Common Stock was held by 690 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 for each quarterly period in 2009 and 2010. There were no cash dividends declared on the Common Stock in 2009 or 2010. On February 17, 2011, the closing price of Forest Common Stock was $39.65.

		Common Stock	
		High	Low
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
2010	First Quarter	$30.08	$22.61
	Second Quarter	32.81	22.85
	Third Quarter	31.89	24.83
	Fourth Quarter	39.32	29.69

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. In December 2010, Forest announced a strategy to separate its Canadian operations through an initial public offering of up to 19.9% of the common stock of its wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which will be the holding company of the Canadian operations, followed by a distribution of the remaining shares of Lone Pine held by Forest to its shareholders, with such distribution occurring at Forest's discretion. 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. See Part I, Item 1A—"Risk Factors—*We may be unable to complete the separation of our Canadian operations as planned or on the terms and manner currently contemplated, and any completed separation may have a negative impact on our business operations, results of operations and financial condition.*"

Unregistered Sales of Equity Securities

We did not make any sales of unregistered equity securities during 2010.

Issuer Purchases of Equity Securities

The table below sets forth information regarding repurchases of our Common Stock during the quarter ended December 31, 2010. 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 2010	3,609	$31.20	—	—
November 2010	2,984	34.06	—	—
December 2010	15,753	35.60	—	—
Fourth Quarter Total	22,346	34.69	—	—

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2005 (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 12/31/05 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 Exchange Act.

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, 2010. 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. We have completed several oil and gas property acquisition and divestiture transactions that affect the comparability of the results for the years presented below. See Part I, Item 1—"Business—Acquisition and Divestiture Activities" and Note 2 to the Consolidated Financial Statements for more information on acquisitions and divestitures.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Oil, natural gas, and NGL sales[1]	$ 853,739	$ 767,830	$ 1,647,171	$1,083,081	$ 814,469
Earnings (loss) from continuing operations	227,521	(923,133)	(1,026,323)	169,306	166,080
Earnings from discontinued operations, net of tax[2]	—	—	—	—	2,422
Net earnings (loss)	$ 227,521	$ (923,133)	$(1,026,323)	$ 169,306	$ 168,502
Basic earnings (loss) per share:[3]					
Earnings (loss) from continuing operations	$ 2.01	$ (8.85)	$ (11.46)	$ 2.20	$ 2.64
Earnings from discontinued operations, net of tax	—	—	—	—	.04
Basic earnings (loss) per common share	$ 2.01	$ (8.85)	$ (11.46)	$ 2.20	$ 2.68
Diluted earnings (loss) per share:[3]					
Earnings (loss) from continuing operations	$ 2.00	$ (8.85)	$ (11.46)	$ 2.16	$ 2.60
Earnings from discontinued operations, net of tax	—	—	—	—	.04
Diluted earnings (loss) per common share	$ 2.00	$ (8.85)	$ (11.46)	$ 2.16	$ 2.64
Total assets	$3,785,388	$3,684,690	$ 5,282,798	$5,695,548	$3,189,072
Long-term debt	$1,869,372	$2,022,514	$ 2,735,661	$1,503,035	$1,204,709
Shareholders' equity	$1,352,787	$1,079,154	$ 1,672,912	$2,411,811	$1,434,006
OPERATING DATA					
Annual production:					
Natural gas (MMcf)	123,782	139,277	141,433	108,042	73,024
Oil (MBbls)	3,185	4,023	4,580	5,297	5,982
NGLs (MBbls)	3,723	3,242	3,451	2,648	2,044
Average sales price:[1]					
Natural gas (per Mcf)	$ 3.94	$ 3.30	$ 7.45	$ 5.79	$ 5.58
Oil (per Bbl)	$ 73.85	$ 55.98	$ 95.07	$ 66.44	$ 56.45
NGLs (per Bbl)	$ 35.16	$ 25.57	$ 45.94	$ 39.75	$ 33.85

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

(2) Discontinued operations relate to the sale of the business assets of our Canadian marketing subsidiary.

(3) In June 2008, the Financial Accounting Standards Board issued authoritative accounting 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. Our total estimated proved reserves as of December 31, 2010 were approximately 2,244 Bcfe of which 81% were in the United States, 17% were in Canada, and 2% were in Italy. Approximately 78% of our estimated proved reserves were natural gas as of December 31, 2010. We currently conduct our operations in three geographical segments: the United States, Canada, and International. See Note 14 to the Consolidated Financial Statements for additional information about our geographical segments. See Item 1—"Business" for a discussion of our business strategy and core operational areas of focus.

In December 2010, we announced our intention to separate our Canadian operations through an initial public offering ("IPO") of up to 19.9% of the common stock of our wholly-owned subsidiary, Lone Pine Resources Inc. ("Lone Pine"), which will be the holding company of the Canadian operations, followed by a distribution of the remaining shares of Lone Pine held by us to our shareholders. The proceeds from the IPO will be used to repay intercompany debt owed to Forest, and the remainder, if any, for general corporate purposes. We expect the IPO to occur in the first half of 2011 and the spin-off of the remaining shares of Lone Pine is expected to occur approximately four months after the IPO; however, we will retain the right to decide whether to commence the spin-off at our discretion. See Part I, Item 1A—"Risk Factors—*We may be unable to complete the separation of our Canadian operations as planned or on the terms and manner currently contemplated, and any completed separation may have a negative impact on our business operations, results of operations and financial condition*."

2010 Summary

A summary of Forest's 2010 results is as follows:

- Oil, natural gas, and natural gas liquids ("NGL") sales volumes decreased 10% to 453 MMcfe per day in 2010 from 501 MMcfe per day in 2009 due to the sale of approximately $1 billion of non-core oil and gas properties primarily in late 2009. Average daily sales volumes, pro forma for oil and gas property divestitures, increased approximately 5% from 2009 to 2010. See Item 1—"Business—Acquisition and Divestiture Activities" for a summary of our acquisitions and divestitures during the last several years.
- Oil, natural gas, and NGL sales increased 11% in 2010 to $854 million from $768 million in 2009. The increase was due to a 23% increase in realized prices partially offset by a 10% decrease in sales volumes.
- Lease operating expenses were 11% lower on a per-unit basis in 2010 as compared to 2009. The decrease was attributable to cost reduction initiatives and the sale of non-core oil and gas properties in late 2009 that had higher per-unit operating costs as compared to the properties we retained.

- Net earnings increased $1.2 billion to $228 million ($2.00 per diluted share) in 2010, compared to a net loss of $923 million ($8.85 per diluted share) in 2009, primarily due to a $1.6 billion pre-tax ceiling test write-down recorded in 2009. See "Results of Operations" below.
- Net cash provided by operating activities decreased $64 million to $533 million in 2010 from $597 million in 2009 primarily due to lower realized gains on commodity derivative instruments of $197 million, partially offset by an increase in commodity prices and a reduction in our current income tax expense.

Recent Trends

Beginning in the second half of 2008 and continuing throughout 2009, the United States and other industrialized countries experienced a significant economic slowdown, which led to a decline in worldwide energy demand. During the same time period, North American natural gas supply increased as a result of increased domestic unconventional gas production. The combination of lower energy demand and higher North American gas supply resulted in significant declines in oil, natural gas, and NGL prices beginning in mid-2008. While oil and NGL prices have steadily improved since the first quarter of 2009 as the worldwide demand for the products increased, North American natural gas prices have not improved proportionate to the increases in oil and NGL prices due to increased domestic supply of natural gas and continued weak industrial demand for natural gas in the United States. For example, the NYMEX WTI price, which is a widely-used benchmark in the pricing of oil and NGLs, increased approximately 105% from $44.60 on December 31, 2008 to $91.38 on December 31, 2010 while the NYMEX Henry Hub price, a widely-used benchmark in the pricing of natural gas, decreased 27% to $4.19 from $5.71 between those same dates.

We expect the volatility in oil, natural gas, and NGL prices to continue in 2011 due primarily to the uncertainty surrounding the worldwide economic recovery and supply and demand fundamentals, particularly for North American natural gas. In this environment, we have hedged approximately 51 Bcfe of our 2011 natural gas production at a weighted-average NYMEX Henry Hub price of $5.54 per MMBtu and 1,460 MBoe of our 2011 oil production at a weighted-average NYMEX WTI floor and ceiling price of approximately $77.50 per barrel and $88.90 per barrel, respectively. Furthermore, as a result of the strength in oil and NGL prices relative to natural gas prices, we expect to direct approximately 80% of our exploration and development capital expenditures in 2011 to liquids-rich prospects. See Item 1—"Business—Core Operational Areas" for a summary of our core operational areas of focus and the amount of capital expenditures we expect to invest in those areas in 2011.

Results of Operations

The following table sets forth selected operating results for the years ended December 31, 2010, 2009, and 2008.

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands, Except per Mcfe and per Share Data)		
Oil, natural gas, and NGL sales	$853,739	$ 767,830	$ 1,647,171
Realized equivalent sales price (per Mcfe)	5.17	4.20	8.69
Net earnings (loss)	227,521	(923,133)	(1,026,323)
Diluted earnings (loss) per common share	2.00	(8.85)	(11.46)
Adjusted EBITDA(1)	718,977	794,717	1,262,713

(1) In addition to reporting net earnings (loss) as defined under GAAP, we also present Adjusted EBITDA, which is a non-GAAP performance measure. See "—Reconciliation of Non-GAAP Measures" at the end of this Item 7 for a reconciliation of Adjusted EBITDA to reported net earnings (loss), which is the most directly comparable financial measure calculated and presented in accordance with GAAP.

Our net earnings (loss) and diluted earnings (loss) per share presented in the table above were primarily impacted by changes in total oil, natural gas, and NGL sales driven by price fluctuations of those commodities between the periods presented and, in 2009 and 2008, due to non-cash ceiling test write-downs of $1.6 billion and $2.4 billion, respectively. Adjusted EBITDA, which excludes the impact of ceiling test write-downs, decreased $76 million to $719 million in 2010 from $795 million in 2009 due to a $197 million decrease in realized commodity hedging gains partially offset by a $86 million increase in oil, natural gas, and NGL sales driven by higher commodity prices. Adjusted EBITDA decreased $468 million in 2009 compared to 2008 due to the significant decrease in oil and natural gas prices during that same period to $4.20 per Mcfe in 2009 from $8.69 per Mcfe in 2008.

Management's analysis of the individual components of the changes in our annual results follows.

Oil and Natural Gas Volumes and Revenues

Natural gas, oil, and NGL sales volumes, revenues, and average sales prices by location for the years ended December 31, 2010, 2009, and 2008, are set forth in the table below.

	Year Ended December 31,											
	2010				2009				2008			
	Natural Gas	Oil	NGLs	Total	Natural Gas	Oil	NGLs	Total	Natural Gas	Oil	NGLs	Total
Sales volumes:	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(MMcf)	(MBbls)	(MBbls)	(MMcfe)
United States	101,346	2,357	3,589	**137,022**	116,029	3,397	3,012	**154,483**	118,120	3,778	3,151	**159,694**
Canada	22,436	828	134	**28,208**	23,248	626	230	**28,384**	23,313	802	300	**29,925**
Totals	123,782	3,185	3,723	**165,230**	139,277	4,023	3,242	**182,867**	141,433	4,580	3,451	**189,619**
Revenues (In Thousands):												
United States	$404,415	$179,312	$123,965	**$707,692**	$386,581	$193,185	$75,813	**$655,579**	$ 890,417	$365,913	$140,339	**$1,396,669**
Canada	83,226	55,896	6,925	**146,047**	73,147	32,016	7,088	**112,251**	162,769	69,520	18,213	**250,502**
Totals	$487,641	$235,208	$130,890	**$853,739**	$459,728	$225,201	$82,901	**$767,830**	$1,053,186	$435,433	$158,552	**$1,647,171**
Average sales price per unit:	$/Mcf	$/Bbl	$/Bbl	$/Mcfe	$/Mcf	$/Bbl	$/Bbl	$/Mcfe	$/Mcf	$/Bbl	$/Bbl	$/Mcfe
United States	$ 3.99	$ 76.08	$ 34.54	**$ 5.16**	$ 3.33	$ 56.87	$ 25.17	**$ 4.24**	$ 7.54	$ 96.85	$ 44.54	**$ 8.75**
Canada	3.71	67.51	51.68	**5.18**	3.15	51.14	30.82	**3.95**	6.98	86.68	60.71	**8.37**
Totals	$ 3.94	$ 73.85	$ 35.16	**$ 5.17**	$ 3.30	$ 55.98	$ 25.57	**$ 4.20**	$ 7.45	$ 95.07	$ 45.94	**$ 8.69**

Our average daily sales volumes in 2010 were 453 MMcfe/d compared to 501 MMcfe/d in 2009. The decrease of 48 MMcfe/d was due to non-core oil and gas property divestitures that occurred primarily in late 2009 offset by production increases attributable to new wells drilled in 2010. Average daily sales volumes, pro forma for oil and gas property divestitures, increased approximately 5% from 2009 to 2010. Oil and natural gas revenues in 2010 were $854 million, an 11% increase as compared to $768 million in 2009. The increase in oil and natural gas revenues was due primarily to the 23% increase in the average realized sales price, which increased to $5.17 per Mcfe in 2010 from $4.20 per Mcfe in 2009, partially offset by the decrease in sales volumes.

Our average daily sales volumes decreased 17 MMcfe/d to 501 MMcfe/d in 2009 from 518 MMcfe/d in 2008. The decrease was primarily due to a reduction in drilling and acquisition activity in 2009 compared to 2008. 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 price, which decreased to $4.20 per Mcfe in 2009 from $8.69 per Mcfe in 2008.

The revenues and average sales prices reflected in the table 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"* below for more information on gains and losses relating to our commodity derivative instruments.

Production Expense

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

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands, Except per Mcfe Data)		
Production expense:			
Lease operating expenses	$118,074	$146,977	$167,830
Production and property taxes	46,079	42,903	82,147
Transportation and processing costs	23,980	20,915	19,472
Production expense	$188,133	$210,795	$269,449
Production expense per Mcfe:			
Lease operating expenses	$ .71	$ .80	$ .89
Production and property taxes	.28	.23	.43
Transportation and processing costs	.15	.11	.10
Production expense per Mcfe	$ 1.14	$ 1.15	$ 1.42

Lease Operating Expenses

Lease operating expenses decreased 20% to $118 million in 2010 from $147 million in 2009. On a per-unit basis, lease operating expenses decreased 11% to $.71 per Mcfe in 2010 from $.80 per Mcfe in 2009. The decrease in total and per-unit lease operating expenses was primarily due to non-core oil and gas property divestitures that occurred during late 2009. The properties divested had higher average per-unit operating costs as compared to the properties we retained. Lease operating expenses decreased 12% to $147 million in 2009 from $168 million in 2008. On a per-unit basis, lease operating expenses decreased 10% to $.80 per Mcfe in 2009 from $.89 per Mcfe in 2008. The decrease in total and per-unit lease operating expenses was attributable to company-wide cost reduction initiatives.

Production and Property Taxes

Production and property taxes, which primarily consist of severance taxes paid on the value of the oil, natural gas, and NGLs sold, were 5.4%, 5.6%, and 5.0% of oil, natural gas, and NGL revenues for the years ended December 31, 2010, 2009, and 2008, respectively. Normal fluctuations occur in the percentage between periods based upon the approval of incentive tax credits in Texas, changes in tax rates, 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 $24 million, or $.15 per Mcfe, in 2010, $21 million, or $.11 per Mcfe, in 2009, and $19 million, or $.10 per Mcfe, in 2008. Transportation and processing costs increased in 2010 primarily due to higher transportation costs incurred for our Canadian and North Louisiana production where additional downstream capacity was purchased.

General and Administrative Expense

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

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands, Except Per Mcfe Data)		
Stock-based compensation costs	$ 35,010	$ 29,165	$ 27,012
Other general and administrative costs	86,400	88,935	95,002
General and administrative costs capitalized	(48,206)	(47,024)	(47,282)
General and administrative expense	$ 73,204	$ 71,076	$ 74,732
General and administrative expense per Mcfe	$ .44	$ .39	$ .39

General and administrative expense increased $2 million to $73 million in 2010 from $71 million in 2009. The increase in general and administrative expense is primarily due to higher stock-based incentive compensation costs primarily driven by an increase in our stock price in 2010. General and administrative expense decreased approximately $4 million to $71 million in 2009 from $75 million in 2008 primarily due to lower software and contract employee expense. 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 40%.

Depreciation, Depletion, and Amortization

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

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands, Except Per Mcfe Data)		
Depreciation, depletion, and amortization expense	$251,618	$303,622	$532,181
Depreciation, depletion, and amortization expense per Mcfe	$ 1.52	$ 1.66	$ 2.81

Depreciation, depletion, and amortization expense ("DD&A") decreased $.14 per Mcfe to $1.52 in 2010 compared to $1.66 in 2009 primarily due to a $1.6 billion non-cash ceiling test write-down of our depletable base recorded in the first quarter 2009. 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.

Ceiling Test Write-Down of Oil and Gas Properties

Pursuant to the ceiling test limitation prescribed by the 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,		
	2010	2009	2008
	(In Thousands)		
Interest costs	$161,531	$175,662	$143,534
Interest costs capitalized	(12,008)	(12,175)	(17,855)
Interest expense	$149,523	$163,487	$125,679

Interest expense in 2010 totaled $150 million compared to $163 million in 2009. The $14 million decrease in interest expense was primarily due to a decrease in average debt levels in 2010 compared to 2009. In January 2010, we redeemed our $150 million 7¾% senior notes. In addition, in December 2009, we repaid all amounts outstanding under our credit facilities using proceeds from non-core oil and gas property sales and have used the credit facilities only to fund short-term borrowing needs during 2010. Interest expense in 2009 totaled $163 million compared to $126 million in 2008. The $38 million increase in interest expense 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 costs capitalized relate to our investments in significant unproved acreage positions that are under development.

In order to effectively reduce the concentration of fixed-rate debt anticipated after the completion of our 2009 oil and gas property divestiture program and the related reduction in our credit facility balance, Forest began entering into fixed-to-floating interest rate swaps in the first quarter of 2009 under which it has swapped, as of December 31, 2010, $500 million in notional amount at an 8.5% fixed rate for an equal notional amount at a weighted-average rate equal to the 1-month LIBOR plus approximately 5.9%. Forest recognized realized gains under these interest rate swaps of $11 million and $7 million during the years ended December 31, 2010 and 2009, respectively. These gains are recorded as realized gains on derivatives rather than as a reduction to interest expense since Forest has not elected to use hedge accounting. See Note 10 to the Consolidated Financial Statements for more information on our interest rate derivatives.

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		
	2010	2009	2008
		(In Thousands)	
Realized losses (gains) on derivatives, net:			
Oil	$ 3,825	$ (11,632)	$ 71,198
Natural Gas	(103,587)	(285,576)	(16,126)
Interest	(12,450)	(10,958)	889
Subtotal realized	(112,212)	(308,166)	55,961
Unrealized losses (gains) on derivatives, net:			
Oil	18,978	35,771	(118,151)
Natural Gas	(47,078)	139,728	(98,618)
NGLs	9,710	—	—
Interest	(19,530)	519	(4,721)
Subtotal unrealized	(37,920)	176,018	(221,490)
Realized and unrealized gains on derivatives, net	$(150,132)	$(132,148)	$(165,529)

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.

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,		
	2010	2009	2008
		(In Thousands)	
Unrealized foreign currency exchange (gains) losses, net	$(14,290)	$(17,974)	$19,481
Realized foreign currency exchange (gains) losses, net	(270)	(88)	959
Unrealized losses on other investments, net	—	2,327	34,042
Accretion of asset retirement obligations	7,194	8,311	7,602
(Gain) loss on debt extinguishment, net	(4,576)	—	97
Other, net	6,199	16,812	5,076
	$ (5,743)	$ 9,388	$67,257

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 its wholly-owned Canadian subsidiary whose functional currency in the Canadian dollar.

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. See Note 9 to the Consolidated Financial Statements for more information on these investments, each of which has had a zero fair value since March 31, 2009.

Accretion of Asset Retirement Obligations

Accretion of asset retirement obligations is the expense recognized to increase the carrying amount of the liability associated with our asset retirement obligations as a result of the passage of time. See Note 1 to the Consolidated Financial Statements for more information on our asset retirement obligations.

Debt Extinguishment

The net gain on debt extinguishment for the year ended December 31, 2010 includes the net gain related to the January 2010 redemption of all $150 million of our 7¾% senior notes due 2014 at 101.292% of par. A net gain was recognized due to the write-off, at the time the notes were redeemed, of unamortized deferred gains resulting from the previous termination of interest rate swaps related to these senior notes. This gain was partially offset by the $1.9 million redemption premium paid to redeem the notes. See Note 4 to the Consolidated Financial Statements for more information on our debt.

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,		
	2010	2009	2008
	(In Thousands, Except Percentages)		
Current income tax	$(13,901)	$ 70,815	$ 11,139
Deferred income tax	134,528	(581,290)	(585,817)
Total income tax	$120,627	$(510,475)	$(574,678)
Effective tax rate	35%	36%	36%

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. 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 available net operating loss carryforwards in 2009. 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 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, natural gas, and NGLs directly impact our level of cash flow generated from operations. Natural gas accounted for approximately 75% of our total 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 and NGLs. 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 17, 2011, we had hedged, via commodity swaps and collar instruments, approximately 71 Bcfe of our total 2011 production, excluding outstanding commodity call options. 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 2011. 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 17, 2011, all of our derivative instrument counterparties are commercial banks that are parties to our credit facilities, or their affiliates. See Part II, Item 7A—"Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk," below for more information on our derivative contracts including commodity call options.

The other primary source of liquidity is our combined U.S. and Canadian credit facilities, which had an aggregate borrowing base of $1.3 billion as of December 31, 2010. 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, 2010 and February 18, 2011.

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 economic 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 2010, we sold certain non-strategic assets for approximately $166 million and, 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, including the redemption of our $285 million principal amount of senior notes that are due in December 2011. 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. 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"), which was $1.3 billion as of December 31, 2010. We 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. 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 2011. 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. 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.

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 greater 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) 4.00 to 1.00 for four consecutive fiscal quarters ending in 2011; and (ii) 3.50 to 1.00 for four consecutive fiscal quarters ending after 2011. 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 17, 2011, all of our derivative counterparties are lenders or their affiliates. 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, 2010 and February 18, 2011, there were no outstanding borrowings under our Credit Facilities. As of December 31, 2010 and February 18, 2011, we had used the Credit Facilities for approximately $2 million in letters of credit.

In connection with the separation of our Canadian operations and the IPO of Lone Pine, we intend to amend the Credit Facilities to (1) set the borrowing base under the Canadian Facility at approximately $300 million, based on current market conditions, and provide that the borrowing base under the Canadian Facility shall be separate from the borrowing base under the U.S. facility, (2) allow Lone Pine to enter into derivative instruments (or hedging agreements) for a portion of its oil, natural gas, and NGL production, (3) provide for Lone Pine to have a stand-alone credit facility upon the completion of the IPO, and (4) provide for Forest to guarantee Lone Pine's stand-alone credit facility until the completion of the spin-off, if it occurs. For a discussion of risks associated with the Lone Pine separation, see Part I, Item 1A—"Risk Factors—*We may be unable to complete the separation of our Canadian operations as planned or on the terms and manner currently contemplated, and any completed* *separation may have a negative impact on our business operations, results of operations and financial condition.*"

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 the 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 (used) provided by investing activities, net cash (used) provided by financing activities, and adjusted discretionary cash flow for the years ended December 31, 2010, 2009, and 2008 were as follows:

	Year Ended December 31,		
	2010	2009	2008
		(In Thousands)	
Net cash provided by operating activities	$ 532,929	$ 596,996	$ 1,070,040
Net cash (used) provided by investing activities	(641,209)	385,372	(2,093,493)
Net cash (used) provided by financing activities	(140,519)	(516,864)	1,016,258
Adjusted discretionary cash flow	573,899	637,847	1,125,400

Net cash provided by operating activities is primarily affected by sales 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 $64 million in 2010 as compared to 2009 was primarily due to lower realized gains on derivatives, decreased sales volumes, and an increased investment in net operating assets (i.e., working capital) partially offset by higher commodity prices. 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 in 2009 as compared to 2008.

The components of net cash (used) provided by investing activities for the years ended December 31, 2010, 2009, and 2008 were as follows:

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands)		
Acquisition, exploration, and development of oil and gas properties[(1)]	$(758,741)	$ (637,831)	$(2,338,488)
Proceeds from sale of assets	166,569	1,054,062	309,940
Acquisition of other fixed assets	(49,037)	(30,887)	(66,005)
Other	—	28	1,060
Net cash (used) provided by investing activities	$(641,209)	$ 385,372	$(2,093,493)

(1) Cash paid for exploration, development, and acquisition costs as reflected in the Consolidated Statements 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 as well as non-cash capital expenditures such as capitalized stock-based compensation costs and, in 2008, common stock issued for oil and gas properties.

Net cash (used) provided by investing activities is primarily comprised of expenditures for the acquisition, exploration, and development of oil and gas properties net of proceeds from the dispositions of oil and gas properties and other capital assets. The $1.0 billion fluctuation in investing cash flows between 2010 and 2009 was primarily due to an $887 million decrease in proceeds from the sale of assets. In the second half of 2008, we initiated a divestiture program to sell certain non-core oil and gas properties. During 2009, we completed the majority of our divestiture program with over $1.0 billion of non-core property sales. 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. In 2008, we acquired producing oil and gas properties located primarily in our Texas Panhandle area. See "*Capital Expenditures*" below for more detail on our capital expenditures for the periods presented.

Net cash used by financing activities of $141 million in 2010 primarily included the redemption of the 7¾% senior notes for $152 million. 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.

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 $574 million, $638 million, and $1.1 billion for 2010, 2009, and 2008, respectively. The fluctuations in adjusted discretionary cash flow between the periods presented were primarily driven by changes in oil, natural gas, and NGL revenues net of realized gains and losses on commodity 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 and reconciliation to net earnings (loss), the most directly comparable financial measure calculated and presented in accordance with GAAP.

Capital Expenditures

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

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands)		
Property acquisitions:			
Proved properties	$ 5,823	$ —	$ 804,616
Unproved properties including leasehold acquisition costs	103,278	56,658	623,316
	109,101	56,658	1,427,932
Exploration:			
Direct costs	180,556	130,021	277,078
Overhead capitalized	23,760	17,682	18,304
	204,316	147,703	295,382
Development:			
Direct costs	450,398	362,425	1,013,817
Overhead capitalized	24,446	29,342	28,978
	474,844	391,767	1,042,795
Total capital expenditures(1)	$788,261	$596,128	$2,766,109

(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. Total capital expenditures also include changes in estimated discounted asset retirement obligations of $(2.1) million, $3 million, and $15 million recorded during the years ended December 31, 2010, 2009, and 2008, respectively.

Due to the downturn in the global economy in late 2008 and the resulting negative impact on the price for oil and natural gas, we chose to significantly reduce our capital expenditures and drilling activity in 2009. As a result of improved economic conditions and higher commodity prices in 2010, we increased our exploration and development capital spending in 2010, focusing our development primarily on our core operational areas. We have established an exploration and development capital budget of $600 million to $650 million for 2011.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2010:

	2011	2012	2013	2014	2015	After 2015	Total
				(In Thousands)			
Bank debt(1)	$ 2,944	$ 1,268	$ —	$ —	$ —	$ —	$ 4,212
Senior notes(2)	430,351	123,501	123,512	678,875	72,500	1,250,729	2,679,468
Derivative liabilities(3)	36,413	—	—	—	—	—	36,413
Other liabilities(4)	5,591	12,951	12,568	9,533	9,241	82,292	132,176
Operating leases(5)	30,515	29,196	27,968	21,740	15,220	22,751	147,390
Unconditional purchase obligations(6)	34,002	7,709	3,311	—	—	—	45,022
Total contractual obligations	$539,816	$174,625	$167,359	$710,148	$96,961	$1,355,772	$3,044,681

(1) Bank debt consists of commitment fees and letter of credit fees on the Credit Facilities. Amounts are estimated based on the $1.3 billion Global Borrowing Base, $2 million in outstanding letters of credit, and no borrowings outstanding, all as of December 31, 2010.

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

(3) Derivative liabilities represent the fair value of our derivative liabilities as of December 31, 2010. 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.

(4) Other liabilities are comprised of pension and other postretirement 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.

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

(6) Unconditional purchase obligations consist primarily of drilling and firm transportation commitments, throughput obligations, and seismic and inventory purchase obligations.

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 2018, totaled approximately $7 million as of December 31, 2010.

Off-balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and other transactions that can give rise to off-balance sheet obligations. As of December 31, 2010, the off-balance sheet arrangements and other transactions that we have entered into include (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, (iv) firm transportation commitments, and (v) other contractual obligations for which we have recorded estimated liabilities on the balance sheet, but the ultimate settlement amounts are not fixed and determinable, such as derivative contracts, pension and other postretirement benefit obligations, and asset retirement obligations. 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 17, 2011, 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 $12 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, 2010 reserves estimates were used for our fourth quarter 2010 depletion calculation. See Part I, Item 1, "Business—Reserves" and Note 16 to the Consolidated Financial Statements for a more complete discussion of our estimated proved reserves as of December 31, 2010.

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 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 the December 31, 2008 spot prices for natural gas and oil of $5.71 per MMBtu and $44.60 per barrel, respectively. We have not incurred a ceiling test write-down since March 31, 2009 through December 31, 2010. Our ceiling test calculations are based on the twelve-month average natural gas and oil prices since December 31, 2009 in accordance with SEC regulations.

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 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 was 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 2010 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 2010, 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 geoscience and engineering data demonstrate, with reasonable certainty, to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods, and governmental regulations, prior to the time at which contracts providing the right to operate expire. 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 may also change. 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 16 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, other than derivative instruments that meet the normal purchase and sales exclusion. 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.

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 offset 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 use the income approach in determining the fair value of our derivative instruments, utilizing present value techniques for valuing our swaps and option-pricing models for valuing our collars, swaptions, and calls. 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 and interest rates, the estimated fair values of our derivative instruments are subject to large fluctuations from period to period. See Item 7A—"Quantitative and Qualitative Disclosures about Market Risk" for a sensitivity analysis of the change in net fair values of our commodity and interest rate derivatives based on a hypothetical change in commodity prices and interest rates.

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 book losses incurred in 2008 and 2009 which were driven entirely from ceiling test write-downs, which are not fair value based measurements. Positive evidence considered by management included book income in 2010 as well as forecasted book income over a reasonable period of time and the utilization of substantially all of our then existing 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 not recorded a valuation allowance against our U.S. deferred tax assets as of December 31, 2010. 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 as of December 31, 2009. As of December 31, 2010, our deferred tax asset position is primarily attributable to the significant 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 recorded $3.9 billion in ceiling test write-downs of the book value of our oil and gas properties in 2008 and 2009 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 periodically change, as do 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, which is included in "Other, net" in the Consolidated Statements of Operations.

Reconciliation of Non-GAAP Measures

Adjusted EBITDA

In addition to reporting net earnings (loss) as defined under generally accepted accounting principles ("GAAP"), Forest also presents adjusted earnings before interest, income 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 (gains) losses on derivative instruments, 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 (loss) (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 non-cash items from earnings, 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. 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,		
	2010	2009	2008
		(In Thousands)	
Net earnings (loss)	$227,521	$ (923,133)	$(1,026,323)
Income tax expense (benefit)	120,627	(510,475)	(574,678)
Unrealized (gains) losses on derivative instruments, net	(37,920)	176,018	(221,490)
Unrealized foreign currency exchange (gains) losses, net	(14,290)	(17,974)	19,481
Unrealized losses on other investments, net	—	2,327	34,042
Realized foreign currency exchange (gains) losses, net	(270)	(88)	959
Interest expense	149,523	163,487	125,679
(Gain) loss on debt extinguishment, net	(4,576)	—	97
Accretion of asset retirement obligations	7,194	8,311	7,602
Ceiling test write-down of oil and gas properties	—	1,575,843	2,369,055
Depreciation, depletion, and amortization	251,618	303,622	532,181
Stock-based compensation	19,550	16,779	17,171
Gain on sale of assets	—	—	(21,063)
Adjusted EBITDA	$718,977	$ 794,717	$ 1,262,713

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 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. Because of this, its utility as a measure of Forest's operating performance has material limitations. 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,		
	2010	2009	2008
		(In Thousands)	
Net cash provided by operating activities	$532,929	$596,996	$1,070,040
Changes in working capital and other items:			
Accounts receivable	7,775	(35,790)	(42,854)
Other current assets	(20,592)	(30,809)	80,214
Accounts payable and accrued liabilities	62,842	47,956	(15,796)
Accrued interest and other current liabilities	7,929	(12,077)	30,686
Current income taxes associated with oil and gas property divestitures	(16,984)	71,571	3,110
Adjusted discretionary cash flow	$573,899	$637,847	$1,125,400

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 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 a commodity hedging strategy. Under our hedging strategy, we enter into commodity swaps, collars, and other derivative instruments with counterparties who, in general, are participants in our credit facilities. These arrangements, which are typically based on prices available in the financial markets at the time the contracts are entered into, are settled in cash and do not require physical deliveries of hydrocarbons.

Swaps

In a typical commodity swap agreement, we receive the difference between a fixed price per unit of production and a price based on an agreed upon published, third-party index if the index price is lower than the fixed price. If the index price is higher, we pay the difference. By entering into swap agreements, we effectively fix the price that we will receive in the future for the hedged production. Our current swaps are settled in cash on a monthly basis. As of December 31, 2010, we had entered into the following swaps:

	Commodity Swaps								
	Natural Gas (NYMEX HH)			Oil (NYMEX WTI)			NGLs (OPIS Refined Products)		
Swap Term	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Fair Value (In Thousands)	Barrels Per Day	Hedged Price per Bbl	Fair Value (In Thousands)	Barrels Per Day	Weighted Average Hedged Price per Bbl	Fair Value (In Thousands)
Calendar 2011	130	$5.60	$49,415	1,000	$85.00	$(3,173)	5,000	$38.15	$(9,710)

Collars

We also enter into collar agreements with third parties. A collar agreement is similar to a swap agreement, except that we receive the difference between the floor price and the index price only if the index price is below the floor price and we pay the difference between the ceiling price and the index price only if the index price is above the ceiling price. As of December 31, 2010, we had entered into the following collars:

	Commodity Collars		
	Oil (NYMEX WTI)		
Collar Term	**Barrels Per Day**	**Weighted Average Hedged Floor and Ceiling Price per Bbl**	**Fair Value (In Thousands)**
Calendar 2011	3,000	$75.00/90.20	$(7,858)

Commodity Options

In connection with several natural gas swaps entered into during the year ended December 31, 2010, we granted option instruments (several commodity swaptions and one call option) to the natural gas swap counterparties in exchange for Forest receiving premium hedged prices on the natural gas swaps. The table below sets forth the outstanding options as of December 31, 2010:

	Commodity Options				
			Oil (NYMEX WTI)		
Instrument	**Option Expiration**	**Underlying Swap Term**	**Underlying Swap Barrels Per Day**	**Underlying Swap Hedged Price per Bbl**	**Fair Value (In Thousands)**
Oil Swaptions	December 2011	Calendar 2012	3,000	$90.00	$(12,356)
Oil Call Option	Monthly in 2011	Monthly in 2011	1,000	90.00	(3,316)

The estimated fair value of all our commodity derivative instruments based on various inputs, including published forward prices, at December 31, 2010 was a net asset of approximately $13.0 million.

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, natural gas, and NGL prices used to calculate the fair values of our commodity derivative instruments at December 31, 2010 would decrease the net fair value of our commodity derivative instruments at December 31, 2010 by approximately $50 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, 2010 and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

Derivative Instruments Entered Into Subsequent to December 31, 2010

Subsequent to December 31, 2010, through February 17, 2011, Forest entered into the following swaps:

	Commodity Swaps			
	Natural Gas (NYMEX HH)		NGLs (OPIS Refined Products)	
Swap Term	**Bbtu Per Day**	**Weighted Average Hedged Price per MMBtu**	**Barrels Per Day**	**Weighted Average Hedged Price per Bbl**
February - December 2011	10	$4.67	—	$ —
Calendar 2012	20	5.40	2,000	45.22

In connection with the Calendar 2012 natural gas swaps shown above, Forest granted the counterparties the following natural gas swaptions:

	Commodity Swaptions		
		Natural Gas (NYMEX HH)	
Option Expiration	**Underlying Swap Term**	**Underlying Swap Bbtu Per Day**	**Underlying Swap Weighted Average Hedged Price per MMBtu**
December 2011	Calendar 2012	20	$5.40

Long-Term Sales Contracts

As of December 31, 2010, we have a delivery commitment of approximately 21 Bbtu/d of natural gas, which provides for a price equal to NYMEX Henry Hub less $1.49 to a buyer through October 31, 2014, unless the Henry Hub price exceeds $6.50 per MMBtu, at which point we share the amount of excess equally with the buyer.

Interest Rate Risk

We periodically enter into interest rate derivative agreements in an attempt to manage the mix of fixed and floating interest rates within our debt portfolio. As of December 31, 2010, we had entered into the following fixed-to-floating 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 2011 - Feb 2014	$500,000	1 month LIBOR + 5.89%	8.50%	$19,011

The estimated fair value of all our interest rate derivative instruments based on various inputs, including published forward rates, at December 31, 2010 was a net asset of approximately $19.0 million.

Due to the volatility of interest rates, the estimated fair values of our interest rate derivative instruments are subject to fluctuations from period to period. For example, a hypothetical 10% increase in the forward 1-month LIBOR interest rates used to calculate the fair values of our interest rate derivative instruments at December 31, 2010 would decrease the net fair value of our interest rate derivative instruments at December 31, 2010 by approximately $2 million. Actual gains or losses recognized related to our interest rate derivative instruments will likely differ from those estimated at December 31, 2010 and will depend exclusively on the future 1-month LIBOR interest rates.

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, 2010, beginning with the fair value of our derivative contracts on December 31, 2009. It has been our experience that commodity prices are subject to large fluctuations, and we expect this volatility to continue. 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. Actual gains and losses recognized related to our commodity derivative instruments will likely differ from those estimated at December 31, 2010 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, 2009	$ (5,389)	$ (596)	$ (5,985)
Premiums received	—	(984)	(984)
Net increase in fair value	118,153	33,041	151,194
Net contract gains recognized	(99,762)	(12,450)	(112,212)
As of December 31, 2010	$ 13,002	$ 19,011	$ 32,013

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, 2010:

	2011	2013	2014	2019	Total
		(Dollar Amounts in Thousands)			
Long-term debt:					
Principal	$285,000	$ 12	$600,000	$1,000,000	$1,885,012
Fixed interest rate	8.00%	7.00%	8.50%	7.25%	7.76%
Effective interest rate(1)	7.25%	7.49%	9.47%	7.24%	7.95%

(1) The effective interest rates on the senior notes differ from the fixed interest rates due to the amortization of related discounts or premiums on the notes. The effective interest rate on the 8% senior notes due 2011 is further reduced from the fixed rate as a result of amortization of deferred gains related to the interest rate swaps terminated in 2002.

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, 2010 and 2009, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Forest Oil Corporation and subsidiaries at December 31, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective December 31, 2009 the Company 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, 2010, 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 23, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
February 23, 2011

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

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 218,145	$ 467,221
Accounts receivable	135,730	126,354
Derivative instruments	60,182	35,643
Deferred income taxes	—	7,108
Inventory	32,633	52,211
Other current assets	34,993	41,455
Total current assets	481,683	729,992
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of $7,813,494 and $7,511,661	1,850,459	1,316,712
Unproved	751,784	828,645
Net oil and gas properties	2,602,243	2,145,357
Other property and equipment, net of accumulated depreciation and amortization of $50,491 and $54,810	113,435	113,850
Net property and equipment	2,715,678	2,259,207
Deferred income taxes	284,021	393,061
Goodwill	256,842	255,908
Derivative instruments	8,244	556
Other assets	38,920	45,966
	$ 3,785,388	$ 3,684,690
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 252,200	$ 284,302
Accrued interest	23,630	25,755
Derivative instruments	36,413	41,358
Deferred income taxes	6,911	—
Current portion of long-term debt	287,092	156,678
Asset retirement obligations	561	4,853
Other current liabilities	22,567	22,074
Total current liabilities	629,374	535,020
Long-term debt	1,582,280	1,865,836
Asset retirement obligations	86,752	88,450
Derivative instruments	—	826
Deferred income taxes	57,560	46,884
Other liabilities	76,635	68,520
Total liabilities	2,432,601	2,605,536
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Preferred stock, none issued and outstanding	—	—
Common stock, 113,594,788 and 112,337,315 shares issued and outstanding	11,359	11,234
Capital surplus	2,684,269	2,652,689
Accumulated deficit	(1,424,905)	(1,652,426)
Accumulated other comprehensive income	82,064	67,657
Total shareholders' equity	1,352,787	1,079,154
	$ 3,785,388	$ 3,684,690

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2010	2009	2008
Revenues:			
Oil, natural gas, and NGL sales	$ 853,739	$ 767,830	$ 1,647,171
Interest and other	1,012	625	3,589
Total revenues	854,751	768,455	1,650,760
Costs, expenses, and other:			
Lease operating expenses	118,074	146,977	167,830
Production and property taxes	46,079	42,903	82,147
Transportation and processing costs	23,980	20,915	19,472
General and administrative	73,204	71,076	74,732
Depreciation, depletion, and amortization	251,618	303,622	532,181
Ceiling test write-down of oil and gas properties	—	1,575,843	2,369,055
Interest expense	149,523	163,487	125,679
Realized and unrealized gains on derivative instruments, net	(150,132)	(132,148)	(165,529)
Gain on sale of assets	—	—	(21,063)
Other, net	(5,743)	9,388	67,257
Total costs, expenses, and other	506,603	2,202,063	3,251,761
Earnings (loss) before income taxes	348,148	(1,433,608)	(1,601,001)
Income tax:			
Current	(13,901)	70,815	11,139
Deferred	134,528	(581,290)	(585,817)
Total income tax	120,627	(510,475)	(574,678)
Net earnings (loss)	$ 227,521	$ (923,133)	$(1,026,323)
Basic earnings (loss) per common share	$ 2.01	$ (8.85)	$ (11.46)
Diluted earnings (loss) per common share	$ 2.00	$ (8.85)	$ (11.46)

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In Thousands)

	Common Stock		Capital Surplus	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive (Loss) Income	Total Shareholders' Equity
Balances at January 1, 2008	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)
Other, net	(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
Other, net	(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
Exercise of stock options	458	46	8,653	—	—	8,699
Employee stock purchase plan	64	6	1,431	—	—	1,437
Restricted stock issued, net of cancellations	889	88	(88)	—	—	—
Amortization of stock-based compensation	—	—	28,440	—	—	28,440
Other, net	(153)	(15)	(6,856)	—	—	(6,871)
Comprehensive earnings:						
Net earnings	—	—	—	227,521	—	227,521
Increase in unfunded postretirement benefits, net of tax	—	—	—	—	(746)	(746)
Foreign currency translation	—	—	—	—	15,153	15,153
Total comprehensive earnings						241,928
Balances at December 31, 2010	113,595	$11,359	$2,684,269	$(1,424,905)	$ 82,064	$ 1,352,787

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2010	2009	2008
Operating activities:			
Net earnings (loss)	$ 227,521	$ (923,133)	$(1,026,323)
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	251,618	303,622	532,181
Unrealized (gains) losses on derivative instruments, net	(37,920)	176,018	(221,490)
Deferred income tax	134,528	(581,290)	(585,817)
Ceiling test write-down of oil and gas properties	—	1,575,843	2,369,055
Stock-based compensation expense	19,550	16,779	17,171
Accretion of asset retirement obligations	7,194	8,311	7,602
Gain on sale of assets	—	—	(21,063)
Unrealized foreign currency exchange (gains) losses, net	(14,290)	(17,974)	19,481
Unrealized losses on other investments, net	—	2,327	34,042
Other, net	2,682	5,773	(2,549)
Changes in operating assets and liabilities:			
Accounts receivable	(7,775)	35,790	42,854
Other current assets	20,592	30,809	(80,214)
Accounts payable and accrued liabilities	(62,842)	(47,956)	15,796
Accrued interest and other current liabilities	(7,929)	12,077	(30,686)
Net cash provided by operating activities	532,929	596,996	1,070,040
Investing activities:			
Capital expenditures for property and equipment:			
Exploration, development, and other acquisition costs	(758,741)	(637,831)	(2,338,488)
Other fixed assets	(49,037)	(30,887)	(66,005)
Proceeds from sales of assets	166,569	1,054,062	309,940
Other, net	—	28	1,060
Net cash (used) provided by investing activities	(641,209)	385,372	(2,093,493)
Financing activities:			
Proceeds from bank borrowings	146,726	868,533	3,203,360
Repayments of bank borrowings	(146,726)	(2,173,687)	(2,195,101)
Issuance of senior notes, net of issuance costs	—	559,767	247,188
Redemption of senior notes	(151,938)	—	(265,000)
Repurchases of senior subordinated notes	(100)	(970)	(4,710)
Proceeds from common stock offering, net of offering costs	—	256,217	—
Proceeds from the exercise of options and from employee stock purchase plan	10,136	4,577	17,740
Change in bank overdrafts	8,128	(39,411)	21,012
Other, net	(6,745)	8,110	(8,231)
Net cash (used) provided by financing activities	(140,519)	(516,864)	1,016,258
Effect of exchange rate changes on cash	(277)	(488)	(285)
Net (decrease) increase in cash and cash equivalents	(249,076)	465,016	(7,480)
Cash and cash equivalents at beginning of year	467,221	2,205	9,685
Cash and cash equivalents at end of year	$ 218,145	$ 467,221	$ 2,205
Cash paid during the year for:			
Interest	$ 152,709	$ 148,242	$ 141,993
Income taxes	53,748	4,302	2,530

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2010, 2009, and 2008

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Description of the Business

Forest Oil Corporation is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil, natural gas, and natural gas liquids ("NGLs") 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 2010 financial statement presentation.

Assumptions, Judgments, and Estimates

In the course of preparing the consolidated financial statements, management makes various assumptions, judgments, and estimates to determine the reported amounts of assets, liabilities, 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. These rules included, among other things, changes to pricing used to estimate oil and gas reserves, broadened the types of technologies that a company may use to establish oil and gas reserves estimates, and broadened the definition of oil and gas producing activities. Accordingly, the Company adopted both the FASB's authoritative accounting guidance and the SEC's 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, 2010, 2009, and 2008, Forest capitalized $48.2 million, $47.0 million, and $47.3 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 2010, 2009, and 2008, the Company capitalized $12.0 million, $12.2 million, and $17.9 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 (as discussed below), 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, 2010 ceiling test was based on average prices during the twelve-month period prior to December 31, 2010 pursuant to the SEC's "Modernization of Oil and Gas Reporting" rule, which was first effective for December 31, 2009 reporting, 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.

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

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, 2010 reserves estimates were used for the Company's fourth quarter 2010 depletion calculation.

Gas gathering assets are depreciated on the units-of-production method whereby the capitalized costs are amortized over the total estimated throughput of the system. 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,	
	2010	2009
	(In Thousands)	
Asset retirement obligations at beginning of period	$93,303	$ 96,991
Accretion expense	7,194	8,311
Liabilities incurred	2,418	4,976
Liabilities settled	(4,297)	(3,352)
Disposition of properties	(7,429)	(13,334)
Revisions of estimated liabilities	(4,542)	(2,089)
Impact of foreign currency exchange rate	666	1,800
Asset retirement obligations at end of period	87,313	93,303
Less: current asset retirement obligations	(561)	(4,853)
Long-term asset retirement obligations	$86,752	$ 88,450

Oil, Natural Gas, and NGL 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.

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, 2010 and 2009, the Company had gas imbalance payables of $7.7 million and $9.9 million, respectively, and gas imbalance receivables of $7.4 million and $7.3 million, respectively.

In 2010, sales to one purchaser were approximately 17% of the Company's total revenues. 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.

Accounts Receivable

The components of accounts receivable are as follows:

	December 31,	
	2010	2009
	(In Thousands)	
Oil, natural gas, and NGL sales	$ 74,707	$ 71,131
Joint interest billings	27,902	33,754
Tax incentive refunds due from Texas	14,291	12,289
Other[1]	20,882	10,648
Allowance for doubtful accounts	(2,052)	(1,468)
Total accounts receivable	$135,730	$126,354

(1) This balance includes $4.3 million and $.8 million due from a third-party broker for sales of Forest common stock at December 31, 2010 and 2009, respectively. Forest received cash payment for these amounts in January 2011 and January 2010, respectively.

Forest's accounts receivable are primarily from purchasers of the Company's oil, natural gas, and NGL sales 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, natural gas, and NGL 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, natural gas, and NGL 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.

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

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 the U.S. dollar denominated intercompany note payable and advances, are reported as a component of shareholders' equity in accumulated other comprehensive income. Statement of operations accounts are translated at the average exchange rate for the quarter, with the translated amounts for each quarter combined for the annual totals.

During 2010, 2009, and 2008, Forest realized \$(.3) million, \$(.1) million, and \$1.0 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 2010, 2009, and 2008, Forest recorded \$(14.3) million, \$(18.0) million, and \$19.5 million, respectively, of unrealized (gains) losses related to the intercompany debt and intercompany advances with Canadian Forest since the debt is denominated in U.S. dollars.

Earnings (Loss) per Share

Basic earnings (loss) per share is computed using the two-class method by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. 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. Holders of restricted stock issued under Forest's stock incentive plans have the right to receive non-forfeitable cash dividends, participating on an equal basis with common stock. Holders of 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. Performance units issued under Forest's stock incentive plans do not participate in dividends in their current form. Holders of performance units participate in dividends paid during the performance units' vesting period only after the performance units vest with common shares being earned by the holders of the performance units. Performance units may vest with no common shares being earned, depending on Forest's shareholder return over the performance units' vesting period in relation to the shareholder returns of specified peers. See Note 7 for more information on Forest's stock-based incentive awards. In summary, restricted stock issued to employees and directors and phantom stock units issued to directors are participating securities and earnings are 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.

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 (e.g. stock options, unvested restricted stock grants, unvested phantom stock units that may be settled in shares, and unvested performance units). No potential common shares shall be included in the computation of any diluted per share amount when a net loss exists. Unvested restricted stock grants were not included in the calculation of diluted earnings per share for the year ended December 31, 2010 as their inclusion would have an antidilutive effect. 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.

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

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands, Except Per Share Amounts)		
Net earnings (loss)	$227,521	$(923,133)	$(1,026,323)
Net earnings attributable to participating securities	(4,482)	—	—
Net earnings (loss) attributable to common stock for basic earnings per share	223,039	(923,133)	(1,026,323)
Adjustment for liability-classified stock-based compensation awards	500	—	—
Net earnings (loss) for diluted earnings per share	$223,539	$(923,133)	$(1,026,323)
Weighted average common shares outstanding during the period for basic earnings per share	110,809	104,336	89,591
Dilutive effects of potential common shares	689	—	—
Weighted average common shares outstanding during the period, including the effects of dilutive potential common shares, for diluted earnings per share	111,498	104,336	89,591
Basic earnings (loss) per common share	$ 2.01	$ (8.85)	$ (11.46)
Diluted earnings (loss) per common share	$ 2.00	$ (8.85)	$ (11.46)

Stock-Based Compensation

Compensation cost is measured at the grant date based on the fair value of the awards (stock options, restricted stock, performance units, 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).

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

Derivative Instruments

The Company records all derivative instruments as either assets or liabilities at fair value, other than the derivative instruments that meet the normal purchase and sales exclusion. 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.

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, 2010 and 2009 totaled $23.9 million and $31.2 million, respectively, and are being amortized over the life of the respective debt instruments.

Inventory

Inventories were comprised of $32.6 million and $52.2 million of materials and supplies as of December 31, 2010 and 2009, 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 of goodwill 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, 2010, 2009, and 2008.

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. The changes in the goodwill balance during the periods presented are solely due to foreign currency exchange rate fluctuations.

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, 2010, 2009, and 2008 are as follows:

	Foreign Currency Translation	Unfunded Postretirement Benefits[1]	Accumulated Other Comprehensive Income (Loss)
		(In Thousands)	
Balance at January 1, 2008	$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
2010 activity	15,153	(746)	14,407
Balance at December 31, 2010	$ 93,667	$(11,603)	$ 82,064

(1) Net of tax.

(2) ACQUISITIONS AND DIVESTITURES:

Acquisitions

On September 30, 2008, Forest acquired producing oil and natural gas properties located in its Texas Panhandle 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. On May 2, 2008, Forest acquired producing oil and natural gas properties located in its East Texas / North Louisiana core area. Forest paid approximately $284 million for the assets.

Divestitures

During the year ended December 31, 2010, Forest sold various non-core U.S. and Canadian oil and natural gas properties for total proceeds of $103.4 million. During 2010, Forest also entered into sales-leaseback transactions involving drilling rigs, receiving $63.1 million in total proceeds. 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 and other 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.

(3) PROPERTY AND EQUIPMENT:

Net property and equipment consists of the following as of the dates indicated:

	December 31, 2010	December 31, 2009
	(In Thousands)	
Oil and gas properties:		
Proved	$ 9,663,953	$ 8,828,373
Unproved	751,784	828,645
Accumulated depletion	(7,813,494)	(7,511,661)
Net oil and gas properties	2,602,243	2,145,357
Other property and equipment:		
Gas gathering, furniture and fixtures, computer hardware and software, and other equipment	163,926	168,660
Accumulated depreciation and amortization	(50,491)	(54,810)
Net other property and equipment	113,435	113,850
Total net property and equipment	$ 2,715,678	$ 2,259,207

The following table sets forth a summary of Forest's investment in unproved properties as of December 31, 2010, by the year in which such costs were incurred:

	Total	2010	2009	2008	2007 and Prior
			(In Thousands)		
United States:					
Acquisition costs	$567,617	$36,811	$35,922	$402,231	$ 92,653
Exploration costs	19,518	9,548	2,348	4,554	3,068
Total United States	587,135	46,359	38,270	406,785	95,721
Canada:					
Acquisition costs	61,602	37,378	9,765	6,222	8,237
Exploration costs	43,918	10,786	3,101	24,091	5,940
Total Canada	105,520	48,164	12,866	30,313	14,177
International:					
Acquisition costs	740	—	—	—	740
Exploration costs	58,389	1,968	1,451	2,360	52,610
Total International	59,129	1,968	1,451	2,360	53,350
Total	$751,784	$96,491	$52,587	$439,458	$163,248

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 and leasehold acquisition costs as well as 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, 2010 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, 2010. The Company continues to pursue commercial development of the Ibhubesi field discovery in South Africa including continued efforts toward securing gas sales contracts.

(4) DEBT:

The components of debt are as follows:

	December 31, 2010				December 31, 2009			
	Principal	Unamortized Premium (Discount)	Other[1]	Total	Principal	Unamortized Premium (Discount)	Other[1]	Total
				(In Thousands)				
U.S. Credit Facility	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Canadian Credit Facility	—	—	—	—	—	—	—	—
8% Senior Notes due 2011[2]	285,000	1,292	800	287,092	285,000	2,583	1,638	289,221
7% Senior Subordinated Notes due 2013[3]	12	—	—	12	112	(2)	—	110
8½% Senior Notes due 2014	600,000	(18,210)	—	581,790	600,000	(24,029)	—	575,971
7¾% Senior Notes due 2014[4]	—	—	—	—	150,000	(1,035)	7,713	156,678
7¼% Senior Notes due 2019	1,000,000	478	—	1,000,478	1,000,000	534	—	1,000,534
Total debt	1,885,012	(16,440)	800	1,869,372	2,035,112	(21,949)	9,351	2,022,514
Less: current portion of long-term debt[2][4]	(285,000)	(1,292)	(800)	(287,092)	(150,000)	1,035	(7,713)	(156,678)
Long-term debt	$1,600,012	$(17,732)	$ —	$1,582,280	$1,885,112	$(20,914)	$ 1,638	$1,865,836

(1) Represents the unamortized portion of deferred gains realized upon termination of interest rate swaps in 2002 and 2003 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.

(2) The 8% senior notes are due December 2011.

(3) In May 2010, the Company repurchased $.1 million in principal amount of the 7% senior subordinated notes due 2013 at par.

(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.

Bank Credit Facilities

As of December 31, 2010, 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 2011. 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. As of December 31, 2010,

(4) DEBT: (Continued)

the borrowing base under the Credit Facilities was $1.3 billion, which Forest has allocated $1.155 billion to the U.S. Credit Facility and $145 million to the Canadian Credit Facility.

Borrowings under the U.S. Facility bear interest at one of two rates as may be elected by Forest. 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 Forest. Borrowings bear interest at a rate that may be based on:

(i) the greater 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. 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.

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

(4) DEBT: (Continued)

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, 2010, 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 June 6, 2007, Forest issued $750 million in principal amount of 7¼% senior notes due 2019 (the "7¼% Notes") at par for net proceeds of $739.2 million, after deducting initial purchaser discounts, and on May 22, 2008, Forest issued an additional $250 million in principal amount of 7¼% Notes at 100.25% of par for net proceeds of $247.2 million, after deducting initial purchaser discounts.

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") 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 at 107.75% of par for proceeds of $133.3 million (net of related offering costs). The 8% 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.

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.

(4) DEBT: (Continued)

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. The net gain was recognized due to the write-off of unamortized deferred gains resulting from the previous termination of interest rate swaps related to the 7¾% Notes. Forest utilized a portion of the sales proceeds received from the December 2009 Permian Basin divestiture to fund the redemption.

Principal Maturities

Principal maturities of the Company's debt at December 31, 2010 are as follows:

	Principal Maturities (In Thousands)
2011	$ 285,000
2012	—
2013	12
2014	600,000
2015	—
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,		
	2010	2009	2008
		(In Thousands)	
Current:			
Federal	$(16,393)	$ 62,366	$ 3,979
Foreign	—	—	3,381
State	2,492	8,449	3,779
	(13,901)	70,815	11,139
Deferred:			
Federal	124,139	(520,320)	(590,078)
Foreign	7,830	(49,293)	23,312
State	2,559	(11,677)	(19,051)
	134,528	(581,290)	(585,817)
	$120,627	$(510,475)	$(574,678)

Income (loss) before income taxes consists of the following for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
		(In Thousands)	
United States Federal	$306,580	$(1,245,387)	$(1,673,671)
Foreign	41,568	(188,221)	72,670
	$348,148	$(1,433,608)	$(1,601,001)

(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,		
	2010	2009	2008
	(In Thousands)		
Federal income tax at 35% of income before income taxes and discontinued operations	$121,852	$(501,763)	$(560,364)
State income taxes, net of federal income tax benefits	3,602	(13,913)	(18,895)
Change in the valuation allowance for deferred tax assets	(3,167)	(10,011)	1,956
Effect of differing tax rates in Canada	(2,833)	11,249	(3,971)
Effect of state statutory rate reductions	—	—	(1,940)
Effect of federal, state, and foreign tax on permanent differences	3,152	555	7,353
Other	(1,979)	3,408	1,183
Total income tax	$120,627	$(510,475)	$(574,678)

Net Deferred Tax Assets and Liabilities

The components of the net deferred tax assets and liabilities by geographical segment at December 31, 2010 and 2009 are as follows:

	December 31, 2010		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Property and equipment	$139,992	$ —	$139,992
Allowance for doubtful accounts	650	—	650
Investment in PERL common stock and Note	18,011	—	18,011
Accrual for postretirement benefits	7,831	265	8,096
Stock-based compensation accruals	15,471	332	15,803
Net operating loss carryforwards	42,992	—	42,992
Capital loss carryforward	—	2,724	2,724
Alternative minimum tax credit carryforward	54,584	—	54,584
Other	9,153	1,654	10,807
Total gross deferred tax assets	288,684	4,975	293,659
Less valuation allowance	—	—	—
Net deferred tax assets	288,684	4,975	293,659
Deferred tax liabilities:			
Property and equipment	—	(57,805)	(57,805)
Unrealized gains on derivative contracts, net	(11,574)	—	(11,574)
Other	—	(4,730)	(4,730)
Total gross deferred tax liabilities	(11,574)	(62,535)	(74,109)
Net deferred tax assets (liabilities)	$277,110	$(57,560)	$219,550

(5) INCOME TAXES: (Continued)

	December 31, 2009		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Property and equipment	$290,636	$ —	$290,636
Unrealized losses 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

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

	December 31, 2010		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax liabilities	$ (6,911)	$ —	$ (6,911)
Non-current deferred tax assets (liabilities)	284,021	(57,560)	226,461
Net deferred tax assets (liabilities)	$277,110	$(57,560)	$219,550

	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

Valuation Allowances

The decrease in the valuation allowance for 2010 relates to $2.0 million of previously reserved tax loss carryforwards of an acquired subsidiary that expired unused and $1.1 million, net, relating to adjustments to Canadian tax loss carryforwards. In 2009, the decrease in valuation allowance of $10.0 million primarily relates to tax loss carryforwards of an acquired subsidiary that were utilized.

(5) INCOME TAXES: (Continued)

Tax Attributes

Net Operating Losses

U.S. federal net operating loss carryforwards ("NOLs") at December 31, 2010 were approximately $119.5 million, with $30.8 million scheduled to expire in 2018 and the remaining $88.7 million scheduled to expire after 2029.

The statute of limitations is closed for the Company's U.S. federal income tax returns for years ending on or before December 31, 2006. Pre-acquisition returns of acquired businesses are also closed for tax years ending on or before December 31, 2006. 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 adjustment is the tax year ending December 31, 1999. The Company's most recent Canadian income tax return that is closed to potential audit adjustment is the tax year ended December 31, 2005.

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 $54.6 million at December 31, 2010, which can be carried forward indefinitely.

Undistributed Earnings from Canadian Operations

The Company's Canadian operations generated a book gain (after tax) of approximately $33.7 million during 2010. As of December 31, 2010, the Company's Canadian operations had reported accumulated undistributed book earnings of approximately $67.8 million. The Company has not provided deferred tax liabilities with respect to U.S. income tax or Canadian withholding taxes related to these undistributed earnings. During 2010, 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, it 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 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 interest expense and penalties in other expense, to the extent they apply.

	Year Ended December 31,	
	2010	2009
	(In Thousands)	
Gross unrecognized tax benefits at beginning of period	$2,665	$ 3,167
Increases in tax positions for prior years	1,078	1,138
Decreases in tax positions for acquired entities	(398)	(1,640)
Gross unrecognized tax benefits at end of period	$3,345	$ 2,665

(6) SHAREHOLDERS' EQUITY:

Common Stock

At December 31, 2010, the Company had 200.0 million shares of common stock, par value $.10 per share, authorized and 113.6 million shares issued and outstanding.

In May 2009, the Company issued 14.4 million 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.

Preferred Stock

Forest has 10.0 million shares of preferred stock, par value $.01 per share, authorized under its Articles of Incorporation. Of those, 7.4 million shares are designated as Senior Preferred Stock and 2.7 million shares are designated as Junior Preferred stock. No preferred stock is issued or outstanding.

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 with a third-party associated with the spin-off.

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:

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, performance stock units, phantom stock units, and other awards may be granted to employees, consultants, and non-employee directors. In 2010, the Company amended the 2007 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 2007 Plan may not exceed 6.7 million shares. As of December 31, 2010, the Company had 3.8 million 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. The aggregate number of shares of common stock that the Company may issue under the 2001 Plan may not exceed 5.0 million shares. As of December 31, 2010, the Company had 519 shares available to be issued under the 2001 Plan.

Compensation Costs

The table below sets forth total stock-based compensation recorded during the years ended December 31, 2010, 2009, and 2008, and the remaining unamortized amounts and weighted average amortization period as of December 31, 2010.

	Stock Options	Restricted Stock	Performance Units	Phantom Stock Units	Total[1]
			(In Thousands)		
Year ended December 31, 2010:					
Total stock-based compensation costs	$ 563	$ 25,377	$ 2,001	$ 6,570	$ 34,511
Less: stock-based compensation costs capitalized	(241)	(9,492)	(509)	(2,988)	(13,230)
Stock-based compensation costs expensed	$ 322	$ 15,885	$ 1,492	$ 3,582	$ 21,281
Unamortized stock-based compensation costs as of December 31, 2010	$ 298	$ 27,070	$ 5,994	$ 9,377[2]	$ 42,739
Weighted average amortization period remaining as of December 31, 2010	.4 years	1.9 years	2.2 years	1.9 years	1.9 years
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
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

(1) The Company also maintains an employee stock purchase plan (which is not included in the table) under which $.5 million, $.6 million, and $.5 million of compensation cost was recognized for the years ended December 31, 2010, 2009, and 2008, respectively.

(2) Based on the closing price of the Company's common stock on December 31, 2010.

(7) STOCK-BASED COMPENSATION: (Continued)

Stock Options

The following table summarizes stock option activity in the Company's stock-based compensation plans for the years ended December 31, 2010, 2009, and 2008.

	Number of Options	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)[1]	Number of Options Exercisable
Outstanding at January 1, 2008	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
Granted	—	—		
Exercised	(457,974)	18.99	6,027	
Cancelled	(32,750)	36.28		
Outstanding at December 31, 2010	1,327,695	$21.67	$22,531	1,283,232

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock, as of the date outstanding or exercised, exceeds the exercise price of the option.

Stock options are granted at the fair market value of one share of common stock on the date of grant and have a term of ten years. Options granted to non-employee directors vest immediately and options granted to officers and other employees vest in increments of 25% on each of the first four anniversary dates of the grant.

The following table summarizes information about options outstanding at December 31, 2010:

	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 - 15.65	334,798	2.44	$15.18	$ 7,684	334,798	2.44	$15.18	$ 7,684
15.93 - 16.85	368,763	2.58	16.83	7,853	368,763	2.58	16.83	7,853
16.88 - 20.47	43,562	3.06	18.33	862	43,562	3.06	18.33	862
20.60 - 36.95	420,966	4.21	23.56	6,132	420,966	4.21	23.56	6,132
42.41 - 42.41	159,606	6.41	42.41	—	115,143	6.39	42.41	—
$14.73 - 42.41	1,327,695	3.54	$21.67	$22,531	1,283,232	3.43	$20.96	$22,531

(7) STOCK-BASED COMPENSATION: (Continued)

Restricted Stock, Performance Stock Units, and Phantom Stock Units

The following table summarizes the restricted stock, performance stock unit, and phantom stock unit activity for the years ended December 31, 2010, 2009, and 2008.

	Restricted Stock			Performance Units			Phantom Stock Units		
	Number of Shares	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)	Number of Units	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)	Number of Units[1]	Weighted Average Grant Date Fair Value	Vest Date Fair Value (In Thousands)[2]
Unvested at January 1, 2008	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	
Awarded	1,006,163	24.69		264,500	31.63		153,135	25.96	
Vested	(645,660)	40.66	19,806	—	—	—	(65,140)	41.88	1,910
Forfeited	(116,865)	36.55		—	—		(52,449)	35.28	
Unvested at December 31, 2010	2,272,321	$32.71		264,500	31.63		510,609	$24.79	

(1) Of the unvested units of phantom stock at December 31, 2010, 271,285 units can be settled in cash, shares of common stock, or a combination of both at the discretion of the Company, while the remaining 239,324 units can only be settled in cash.

(2) Of the phantom stock units that vested during 2010, 63,750 units were settled in shares of common stock and 1,390 units were settled in cash. Of the phantom stock units that vested during 2009, 7,429 units were settled in shares of common stock and 4,680 units were settled in cash. Of the phantom stock units that vested in 2008, 70,050 were settled in shares of common stock and 250 units were settled in cash.

The grant date fair value of the restricted stock and phantom stock units was determined by averaging 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. 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, certain involuntary terminations, or a change in control of the Company in accordance with the term of the underlying agreement. The phantom stock units can be settled in cash, shares of common stock, or a combination of both. The phantom stock units have been accounted for as a liability within the consolidated financial statements.

The performance units were awarded to Forest's officers during 2010. The grant date fair value of the performance units was determined using a process that takes into account probability-weighted shareholder returns assuming a large number of possible stock price paths (which are modeled based on inputs such as volatility and the risk-free interest rate). Under the terms of the award agreements, each performance unit represents a contractual right to receive one share of Forest's common stock; provided that the actual number of shares that may be deliverable under an award will range from 0% to 200% of the number of performance units awarded, depending on Forest's relative total shareholder return in comparison to an identified peer group during the thirty-six month performance period ending on March 31, 2013.

(7) STOCK-BASED COMPENSATION: (Continued)

Employee Stock Purchase Plan

The Company has a 1999 Employee Stock Purchase Plan (the "ESPP"), under which it is authorized to issue up to .8 million 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, 2010, the Company had .4 million shares available for issuance under the ESPP.

The fair value of each stock purchase right granted under the ESPP during 2010, 2009, and 2008 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:

	Year Ended December 31,		
	2010	2009	2008
Expected option life	3 months	3 months	3 months
Risk free interest rates	.08% - .17%	.08% - .22%	.85% - 1.96%
Estimated volatility	38%	62%	76%
Dividend yield	0%	0%	0%
Weighted average fair market value of purchase rights granted	$7.78	$4.70	$11.72

(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 Company 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

As of December 31, 2010, it is anticipated that the Company will be required to provide benefit payments from the Forest Pension Plan trust and the Wiser Pension Plan trust and fund benefit payments directly for the SERP and the other postretirement benefits plans in 2011 through 2015 and in the aggregate for the years 2016 through 2020 in the following amounts:

	2011	2012	2013	2014	2015	2016-2020
			(In Thousands)			
Forest Pension Plan[1]	$2,411	$2,362	$2,367	$2,284	$2,230	$10,263
SERP	132	129	126	122	119	535
Wiser Pension Plan[1]	869	858	852	840	829	3,963
Postretirement benefits (U.S.)	600	576	566	559	544	2,898
Postretirement benefits (Canada)	47	51	51	50	52	299

(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 2011 totaling $.1 million to the Plans and $.5 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 plans.

	Year Ended December 31,			
	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
	(In Thousands)			
Benefit obligation at the beginning of the year	$41,205	$39,780	$ 9,057	$7,619
Service cost	—	—	668	543
Interest cost	2,005	2,207	481	493
Actuarial loss	2,273	2,475	651	853
Benefits paid	(3,270)	(3,257)	(762)	(740)
Medicare reimbursements	—	—	66	59
Retiree contributions	—	—	66	68
Impact of foreign currency exchange rate	—	—	62	162
Benefit obligation at the end of the year	$42,213	$41,205	$10,289	$9,057

Fair Value of Plan Assets

The Company's Pension Plan assets measured at fair value on a recurring basis are set forth by level within the fair value hierarchy in the table below as of the dates indicated (see Note 9 for information on the fair value hierarchy). There were no changes to the valuation techniques used

(8) EMPLOYEE BENEFITS: (Continued)

during the period. There are no assets set aside under the SERP and the postretirement benefit plans. During 2010, the amount of contributions and Medicare reimbursements, in the case of the postretirement benefit plans, equals the amount of benefits paid.

	December 31, 2010				December 31, 2009			
	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	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]	$ —	$10,000	$ —	$10,000	$ —	$10,251	$ —	$10,251
International stock funds[2]	11,001	—	—	11,001	9,625	—	—	9,625
Investment funds—fixed income:								
Short-term fund[3]	267	—	—	267	1,375	—	—	1,375
Bond fund[4]	8,180	—	—	8,180	7,992	—	—	7,992
Oil and gas royalty interests[5]	—	—	161	161	—	—	136	136
	$19,448	$10,000	$161	$29,609	$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 - 130 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, 2010, the sector weighting of this fund was comprised of the following: information technology (19%), financials (17%), health care (13%), energy (12%), consumer discretionary (11%), and other (28%). The fair value of this investment fund was determined based on the net asset value per unit provided by the investee.

(2) These two investment funds seek long-term growth of principal and income by investing primarily in diversified portfolios of equity securities issued by foreign, medium-to-large companies in international markets including emerging markets. The first fund typically holds 50 - 100 securities and seeks to invest in solid, well-established global leaders with emphasis on strong corporate governance, positive future growth opportunities, and growing return on capital. As of December 31, 2010, the sector weighting of this fund, which seeks diversification across regions, countries, and market sectors, was comprised of the following: financials (21%), consumer discretionary (15%), healthcare (14%), information technology (12%), and other (38%). The second fund holds 76 securities and seeks to obtain growth through long-term appreciation of its holdings. As of December 31, 2010, the sector weighting of this fund, which invests in Asian (excluding Japanese) growth equities with a focus on domestic demand growth rather than an export orientation, was comprised of the following: financials (32%), consumer discretionary (16%), information technology (15%), consumer staples (12%), and other (25%). The fair value of these investment funds was determined based on the funds' net asset values per unit, which are 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, 2010, the sector weighting of this fund was comprised of the following: investment grade credit (41%), government-related (23%), mortgage (11%), 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.

(4) This investment fund consists of a diversified portfolio of bonds. 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, 2010, the sector weighting of this fund was comprised of the following: mortgage (45%), government-related (22%), investment grade credit (17%), and other (16%). 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 estimated discounted 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.

	Year Ended December 31,			
	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
	(In Thousands)			
Fair value of plan assets at beginning of the year	$29,379	$24,451	$ —	$ —
Actual return on plan assets	2,927	6,341	—	—
Retiree contributions	—	—	66	68
Medicare reimbursements	—	—	66	59
Employer contribution	573	1,844	630	613
Benefits paid	(3,270)	(3,257)	(762)	(740)
Fair value of plan assets at the end of the year	$29,609	$29,379	$ —	$ —

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).

	Year Ended December 31, 2010
	Oil and Gas Royalty Interests
	(In Thousands)
Balance at beginning of period	$136
Actual return on plan assets	79
Purchases, sales, and settlements (net)	(54)
Transfers in and/or out of Level 3	—
Balance at end of period	$161

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 allocation target is up to 75% equity, with discretion to vary the mix temporarily, in response to market conditions.

(8) EMPLOYEE BENEFITS: (Continued)

The weighted average asset allocations of the Forest Pension Plan and Wiser Pension Plan are set forth in the following table as of the dates indicated:

	December 31,			
	Forest Pension Plan		Wiser Pension Plan	
	2010	2009	2010	2009
Fixed income securities	29%	32%	27%	31%
Equity securities	70%	67%	73%	69%
Other	1%	1%	0%	0%
	100%	100%	100%	100%

Funded Status

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

	December 31,			
	Pension Benefits		Postretirement Benefits	
	2010	2009	2010	2009
	(In Thousands)			
Excess of benefit obligation over plan assets	$(12,604)	$(11,827)	$(10,289)	$(9,057)
Unrecognized actuarial loss (gain)	18,332	17,642	(224)	(913)
Net amount recognized	$ 5,728	$ 5,815	$(10,513)	$(9,970)
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability—noncurrent	$(12,604)	$(11,827)	$(10,289)	$(9,057)
Accumulated other comprehensive income—net actuarial loss (gain)	18,332	17,642	(224)	(913)
Net amount recognized	$ 5,728	$ 5,815	$(10,513)	$(9,970)

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,	
	2010	2009
	(In Thousands)	
Projected benefit obligation	$42,213	$41,205
Accumulated benefit obligation	42,213	41,205
Fair value of plan assets	29,609	29,379

(8) EMPLOYEE BENEFITS: (Continued)

Annual Periodic Expense and Actuarial Assumptions

The following tables set forth the components of the net periodic cost and the underlying weighted average actuarial assumptions.

	Year Ended December 31,					
	Pension Benefits			Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
	(Dollar Amounts In Thousands)					
Service cost	$ —	$ —	$ —	$ 668	$ 543	$ 518
Interest cost	2,005	2,207	2,277	481	493	495
Expected return on plan assets	(1,952)	(1,600)	(2,534)	—	—	—
Recognized actuarial loss (gain)	606	2,119	726	(21)	(105)	(91)
Total net periodic expense	$ 659	$ 2,726	$ 469	$ 1,128	$ 931	$ 922
Assumptions used to determine net periodic expense:						
Discount rate	5.04%	5.84%	5.77%	5.55% & 4.50%	6.12% & 6.74%	5.39% & 6.02%
Expected return on plan assets	7%	7%	7%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:						
Discount rate	4.50%	5.04%	5.84%	5.15% & 4.00%	5.55% & 4.50%	6.12% & 6.74%

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, 2011, will include expense of $.6 million resulting from the amortization of its related accumulated actuarial loss included in accumulated other comprehensive income at December 31, 2010.

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 9.5% in 2011, 9.0% in 2012, 8.5% in 2013, 8.0% in 2014, 7.5% in 2015, and 7.0% thereafter for the medical benefits and 6.5% in 2011, 6.2% in 2012, 5.9% in 2013, 5.6% in 2014, 5.3% in 2015, and 5.0% thereafter for the dental benefits.

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:

	Year Ended December 31, 2010	
	Postretirement Benefits	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	$ 236	$ (226)
Effect on postretirement benefit obligation	1,731	(1,390)

(8) EMPLOYEE BENEFITS: (Continued)

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 \$3.9 million in 2010, \$4.1 million in 2009, and \$3.9 million in 2008.

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. The Company's estimate of costs expected to be paid in 2011 to maintain these life insurance policies is \$1.0 million. 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. Forest recognized accretion expense related to the split dollar life insurance obligations of \$1.0 million, \$1.4 million, and \$.6 million for the years ended December 31, 2010, 2009, and 2008, respectively. The discount rates used to determine the accretion expense were 4.01%, 5.64%, and 5.55% for the years ended December 31, 2010, 2009, and 2008, respectively. The split dollar life insurance obligation recognized in the balance sheet was \$7.3 million and \$8.2 million as of December 31, 2010 and 2009, respectively. The discount rates used to determine the obligations were 4.08% and 4.01% as of December 31, 2010 and 2009, respectively. The cash surrender value of the split dollar life insurance policies recognized in the balance sheets was \$3.3 million and \$3.1 million as of December 31, 2010 and 2009, respectively.

(9) FAIR VALUE MEASUREMENTS:

The Company's assets and liabilities measured at fair value on a recurring basis at December 31, 2010 are set forth by level within the fair value hierarchy in the table below.

Description	Using Significant Other Observable Inputs (Level 2)[1]
	(In Thousands)
Assets:	
Derivative instruments[2]	
Commodity	\$49,415
Interest rate	19,011
Total Assets	\$68,426
Liabilities:	
Derivative instruments[2]	
Commodity	\$36,413
Interest rate	—
Total Liabilities	\$36,413

(1) The authoritative accounting guidance regarding fair value measurements for assets and liabilities measured at fair value establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers consist of: 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 its derivative instruments under the Level 2 hierarchy.

(9) FAIR VALUE MEASUREMENTS: (Continued)

(2) The Company's derivative assets and liabilities include commodity and interest rate derivatives (see Note 10 for more information on these instruments). The Company utilizes present value techniques and option-pricing models for valuing its derivatives. 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.

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 years ended December 31, 2009 and 2008. The Company did not have assets or liabilities with any fair value measured at fair value on a recurring basis using significant unobservable inputs (Level 3) at any time during 2010.

	Year Ended December 31, 2009		Year Ended December 31, 2008
	Equity Securities	Debt Securities[(1)]	Debt Securities[(1)]
		(In Thousands)	
Balance at beginning of period	$ —	$ 1,670	$ 15,023
Total net losses (realized/unrealized):			
Included in earnings	(657)	(1,670)	(13,353)
Included in other comprehensive income	—	—	—
Purchases, sales, issuances, and settlements:			
Purchases	—	—	—
Issuances	—	—	—
Sales	—	—	—
Settlements	—	—	—
Transfers in and/or out of Level 3[(2)(3)]	657	—	—
Balance at end of period	$ —	$ —	$ 1,670
The amount of total losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at end of period	$(657)	$(1,670)	$(15,027)

(1) The Company's 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") that was received as a portion of the total consideration for the sale of the Company's Alaska assets in 2007. In March 2009, PERL filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. The Company used its own assumptions as to what market participants would assume regarding future cash flows and risk-adjusted discount rates in valuing the PERL Note, which is currently valued at zero and has been since March 31, 2009.

(2) The Company's investment in PERL common stock, which the Company also received as a portion of the total consideration for the sale of the Company's Alaska assets in 2007, was transferred from Level 1 to Level 3 in the first quarter of 2009 when PERL's common stock was suspended from trading for failure to meet the continued stock exchange listing requirements. The Company used its own assumptions as to what market participants would assume regarding future cash flows and risk-adjusted discount rates in valuing the PERL common stock, which is currently valued at zero and has been since March 31, 2009.

(3) The Company's policy is to recognize transfers in and/or out of fair value hierarchy levels as of the beginning of the reporting period in which the event or change in circumstances caused the transfer.

The table below sets forth 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 periods presented. These gains and losses are reported in the Consolidated Statements of Operations in the line items shown in the table. The Company did not record any gains

(9) FAIR VALUE MEASUREMENTS: (Continued)

or losses (realized and unrealized) related to assets or liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during 2010.

	Year Ended December 31, 2009		Year Ended December 31, 2008	
	Equity Securities	Debt Securities	Debt Securities	
	Other, net	Other, net	Other, net	Interest and 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 relating to assets still held at end of period	$657	$1,670	$15,027	$ —

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

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

	December 31, 2010		December 31, 2009	
	Carrying Amount	Fair Value[1]	Carrying Amount	Fair Value[1]
	(In Thousands)			
Assets:				
Cash and cash equivalents	$ 218,145	$ 218,145	$ 467,221	$467,221
Derivative instruments	68,426	68,426	36,199	36,199
Liabilities:				
Derivative instruments	36,413	36,413	42,184	42,184
8% senior notes due 2011	287,092	300,658	289,221	296,400
7% senior subordinated notes due 2013	12	12	110	112
8½% senior notes due 2014	581,790	660,000	575,971	630,000
7¾% senior notes due 2014	—	—	156,678	151,938
7¼% senior notes due 2019	1,000,478	1,022,670	1,000,534	992,500

(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 fair values of the senior notes and senior subordinated notes were estimated based on quoted market prices. The methods used to determine the fair values of the derivative instruments are discussed above. See also Note 10 for more information on the derivative instruments.

(10) DERIVATIVE INSTRUMENTS:

Commodity Derivatives

Forest periodically enters into derivative instruments such as 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.

(10) DERIVATIVE INSTRUMENTS: (Continued)

The table below sets forth Forest's outstanding commodity swaps and costless collars as of December 31, 2010.

Commodity Swaps and Collars

Term	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)		NGLs (OPIS Refined Products)	
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Barrels Per Day	Weighted Average Hedged Price per Bbl	Barrels Per Day	Weighted Average Hedged Price per Bbl
Swaps:						
Calendar 2011	130	$5.60	1,000	$ 85.00	5,000	$38.15
Collars:						
Calendar 2011	—	—	3,000	75.00/90.20(1)	—	—

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

In connection with several natural gas swaps entered into during the year ended December 31, 2010, Forest granted option instruments (several commodity swaptions and one call option) to the natural gas swap counterparties in exchange for Forest receiving premium hedged prices on the natural gas swaps. The table below sets forth the outstanding options as of December 31, 2010.

Commodity Options

Instrument	Option Expiration	Underlying Swap Term	Oil (NYMEX WTI)	
			Underlying Swap Barrels Per Day	Underlying Swap Hedged Price per Bbl
Oil Swaptions	December 2011	Calendar 2012	3,000	$90.00
Oil Call Option	Monthly in 2011	Monthly in 2011	1,000	90.00

Derivative Instruments Entered Into Subsequent to December 31, 2010

Subsequent to December 31, 2010, through February 17, 2011, Forest entered into the following swaps:

Commodity Swaps

Swap Term	Natural Gas (NYMEX HH)		NGLs (OPIS Refined Products)	
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Barrels Per Day	Weighted Average Hedged Price per Bbl
February - December 2011	10	$4.67	—	$ —
Calendar 2012	20	5.40	2,000	45.22

In connection with the Calendar 2012 natural gas swaps shown above, Forest granted the counterparties the following natural gas swaptions:

Commodity Swaptions

Option Expiration	Underlying Swap Term	Natural Gas (NYMEX HH)	
		Underlying Swap Bbtu Per Day	Underlying Swap Weighted Average Hedged Price per MMBtu
December 2011	Calendar 2012	20	$5.40

(10) DERIVATIVE INSTRUMENTS: (Continued)

Interest Rate Derivatives

Forest periodically enters into interest rate derivative agreements in an attempt to manage the mix of fixed and floating interest rates within its debt portfolio. 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. The table below sets forth Forest's outstanding fixed-to-floating interest rate swaps as of December 31, 2010.

Interest Rate Swaps

Remaining Swap Term	Notional Amount (In Thousands)	Weighted Average Floating Rate	Weighted Average Fixed Rate
January 2011 - February 2014	$500,000	1 month LIBOR + 5.89%	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 for more information on Forest's derivative instruments.

	December 31, 2010	December 31, 2009
	(In Thousands)	
Assets:		
Commodity derivatives:		
Current assets: derivative instruments	$49,415	$35,454
Interest rate derivatives:		
Current assets: derivative instruments	10,767	189
Derivative instruments	8,244	556
Total assets	68,426	36,199
Liabilities:		
Commodity derivatives:		
Current liabilities: derivative instruments	36,413	40,843
Interest rate derivatives:		
Current liabilities: derivative instruments	—	515
Derivative instruments	—	826
Total liabilities	36,413	42,184
Net derivative fair value	$32,013	$(5,985)

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

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands)		
Commodity derivatives:			
Realized (gains) losses	$ (99,762)	$(297,208)	$ 55,072
Unrealized (gains) losses	(18,390)	175,499	(216,769)
Interest rate derivatives:			
Realized (gains) losses	(12,450)	(10,958)	889
Unrealized (gains) losses	(19,530)	519	(4,721)
Realized and unrealized gains on derivative instruments, net	$(150,132)	$(132,148)	$(165,529)

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. As of December 31, 2010, all of the derivative counterparties are lenders, 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. None of these counterparties require collateral beyond that already pledged under the Credit Facilities. Forest is currently evaluating the impact, if any, that the recently enacted Dodd-Frank Wall Street Reform and Consumer Protection Act will have on the existing derivative transactions under the Company's currently outstanding ISDA Master Agreements and Schedules, as well as Forest's ability to enter into such transactions and agreements in the future.

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 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. 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.

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

(10) DERIVATIVE INSTRUMENTS: (Continued)

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 Forest, the fair value of which was $36.5 million at December 31, 2010. 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, 2010, Forest owed a net derivative liability to two counterparties, the fair value of which was $4.5 million. If the netting provisions of the ISDA Master Agreements did not exist, at December 31, 2010, Forest would be exposed to a risk of loss of $68.4 million under its derivative agreements and Forest's derivative counterparties would be exposed to a risk of loss of $36.4 million.

(11) 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, 2010.

	2011	2012	2013	2014	2015	After 2015	Total
				(In Thousands)			
Operating leases[(1)]	$30,515	$29,196	$27,968	$21,740	$15,220	$22,751	$147,390
Unconditional purchase obligations[(2)]	14,025	7,709	3,311	—	—	—	25,045
	$44,540	$36,905	$31,279	$21,740	$15,220	$22,751	$172,435

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

(2) Includes unconditional purchase obligations for seismic, firm transportation, and throughput. Payments under these firm transportation unconditional purchase obligations were $6.2 million in 2010, $4.1 million in 2009, and $3.9 million in 2008. Payments under these seismic unconditional purchase obligations were $4.2 million in 2010. There have been no payments made under the unconditional purchase obligation for throughput prior to December 31, 2010.

Net rental payments under non-cancelable operating leases applicable to exploration and development activities and capitalized to oil and gas properties approximated $14.5 million in 2010, $10.5 million in 2009, and $15.5 million in 2008. Net rental payments under operating leases, including compressor rentals, charged to expense approximated $19.1 million in 2010, $24.2 million in 2009, and $18.4 million in 2008. The Company has no leases that are accounted for as capital leases.

As of December 31, 2010, Forest has a delivery commitment of approximately 21 Bbtu/d of natural gas, which provides for a price equal to NYMEX Henry Hub less $1.49 to a buyer through October 31, 2014, unless the Henry Hub price exceeds $6.50 per MMBtu, at which point Forest shares the amount of excess equally with the buyer.

In August 2007, Forest sold all of its Alaska assets to Pacific Energy Resources Ltd. and its related entities ("PERL"). On March 9, 2009, PERL filed for bankruptcy. As part of the plan of liquidation of its bankruptcy, PERL "abandoned" its interests in many of the Alaska assets sold to it by Forest, including the Trading Bay Unit and Trading Bay Field ("Trading Bay"). At the time of the abandonment of PERL's interests in Trading Bay, Union Oil Company of California ("Unocal") was the operator of those assets. On December 2, 2010, Unocal filed a lawsuit styled *Union Oil Company of California v. Forest Oil Corporation* in Anchorage District Court, Alaska. Forest has removed the case to

(11) COMMITMENTS AND CONTINGENCIES: (Continued)

federal district court in Anchorage, Alaska. In the lawsuit, Unocal complains about PERL's abandonment of Trading Bay and states that PERL has failed to pay approximately $48.0 million in joint interest billings owed on those properties to date. Unocal further claims that Forest is liable for PERL's share of all joint interest billings owed on Trading Bay, in arrears and in the future, because (1) Forest was the predecessor party to the contracts governing the operations at Trading Bay, (2) Unocal did not agree that, in conjunction with Forest's sale of its Alaska assets, Forest would be released of its obligations under the Trading Bay contracts, and (3) PERL has defaulted on the joint interest billings owed on Trading Bay since October 2008. Although Forest is unable to predict the final outcome of this case, Forest believes that the allegations of this lawsuit are without merit, and Forest intends to vigorously defend the action.

Forest, in the ordinary course of business, is a party to various other 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. Forest is also involved in a number of governmental proceedings in the ordinary course of business, including environmental matters.

(12) COSTS, EXPENSES, AND OTHER:

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

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands)		
Unrealized foreign currency exchange (gains) losses, net	$(14,290)	$(17,974)	$19,481
Realized foreign currency exchange (gains) losses, net	(270)	(88)	959
Unrealized losses on other investments, net	—	2,327	34,042
Accretion of asset retirement obligations	7,194	8,311	7,602
(Gain) loss on debt extinguishment, net	(4,576)	—	97
Other, net	6,199	16,812	5,076
	$ (5,743)	$ 9,388	$67,257

(13) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In Thousands, Except Per Share Amounts)			
2010				
Oil, natural gas, and NGL sales	$ 221,729	$207,954	$210,181	$213,875
Net earnings[1]	$ 109,162	$ 33,254	$ 68,911	$ 16,194
Basic earnings per share	$ .97	$ .29	$ .61	$ .14
Diluted earnings per share	.97	.29	.60	.14
2009				
Oil, natural gas, and NGL 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

(1) Net earnings have been subject to large fluctuations due to Forest's election not to use cash flow hedge accounting for derivative instruments as discussed in Note 10 and, in the first quarter of 2009, due to a ceiling test write-down of oil and gas properties as discussed in Note 1.

(14) GEOGRAPHICAL SEGMENTS:

At December 31, 2010, 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

(14) GEOGRAPHICAL SEGMENTS: (Continued)

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, 2010			
	United States	Canada	International	Total Company
	(In Thousands)			
Oil, natural gas, and NGL sales	$ 707,692	$146,047	$ —	$ 853,739
Costs and expenses:				
Lease operating expenses	92,394	25,680	—	118,074
Production and property taxes	43,656	2,423	—	46,079
Transportation and processing costs	13,242	10,738	—	23,980
Depletion	179,656	62,846	—	242,502
Accretion of asset retirement obligations	6,057	1,036	101	7,194
Segment earnings (loss)	$ 372,687	$ 43,324	$ (101)	$ 415,910
Capital expenditures(1)	$ 580,479	$203,031	$ 4,751	$ 788,261
Goodwill(2)	$ 239,420	$ 17,422	$ —	$ 256,842
Long-lived assets(3)	$1,978,636	$645,405	$91,637	$2,715,678
Total assets(2)	$2,978,889	$713,670	$92,829	$3,785,388

(1) Includes changes in estimated discounted asset retirement obligations of $(2.1) million recorded during the year ended December 31, 2010.

(2) As of December 31, 2010.

(3) Consists of net property and equipment as of December 31, 2010.

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

	Year Ended December 31, 2010
	(In Thousands)
Segment earnings	$ 415,910
Interest and other income	1,012
General and administrative expense	(73,204)
Depreciation and amortization expense	(9,116)
Interest expense	(149,523)
Realized and unrealized gains on derivative instruments, net	150,132
Other, net	12,937
Earnings before income taxes	$ 348,148

(14) GEOGRAPHICAL SEGMENTS: (Continued)

	Oil and Gas Operations			
	Year Ended December 31, 2009			
	United States	Canada	International	Total Company
	(In Thousands)			
Oil, natural gas, and NGL 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 changes in estimated discounted asset retirement obligations of $2.9 million recorded 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)

(14) GEOGRAPHICAL SEGMENTS: (Continued)

	Oil and Gas Operations			
	Year Ended December 31, 2008			
	United States	Canada	International	Total Company
	(In Thousands)			
Oil, natural gas, and NGL 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 changes in estimated discounted asset retirement obligations of $15.0 million recorded 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)

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 2010. This purchaser represented $145.1 million of consolidated revenues. 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.

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION:

The Company's 8% senior notes due 2011, 8½% 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, 2010 and 2009, and for the three years in the period ended December 31, 2010 on an issuer (parent company), guarantor subsidiary, non-guarantor subsidiaries, eliminating entries, and consolidated basis. Eliminating entries presented are necessary to combine the entities.

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS

(In Thousands)

	December 31, 2010					December 31, 2009				
	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	$ 216,580	$ 3	$ 1,562	$ —	**$ 218,145**	$ 456,978	$ 379	$ 9,864	$ —	**$ 467,221**
Accounts receivable	50,024	50,211	36,291	(796)	**135,730**	79,857	24,406	22,671	(580)	**126,354**
Deferred income taxes	—	—	—	—	**—**	6,589	519	—	—	**7,108**
Note receivable from subsidiary	250,183	—	—	(250,183)	**—**	135,529	—	—	(135,529)	**—**
Other current assets	112,287	755	14,766	—	**127,808**	115,663	797	12,849	—	**129,309**
Total current assets	629,074	50,969	52,619	(250,979)	**481,683**	794,616	26,101	45,384	(136,109)	**729,992**
Property and equipment, at cost	7,403,398	1,198,138	1,978,127	—	**10,579,663**	7,093,082	1,074,610	1,657,986	—	**9,825,678**
Less accumulated depreciation, depletion, and amortization	5,618,604	1,049,647	1,195,734	—	**7,863,985**	5,502,530	994,005	1,069,936	—	**7,566,471**
Net property and equipment	1,784,794	148,491	782,393	—	**2,715,678**	1,590,552	80,605	588,050	—	**2,259,207**
Investment in subsidiaries	436,772	—	—	(436,772)	**—**	308,424	—	—	(308,424)	**—**
Goodwill	216,460	22,960	17,422	—	**256,842**	216,460	22,960	16,488	—	**255,908**
Due from (to) parent and subsidiaries net	187,404	(13,388)	(174,016)	—	**—**	215,679	(60,884)	(154,795)	—	**—**
Deferred income taxes	330,309	—	—	(46,288)	**284,021**	395,519	—	—	(2,458)	**393,061**
Other assets	44,936	6	2,222	—	**47,164**	44,087	6	2,429	—	**46,522**
	$3,629,749	$ 209,038	$ 680,640	$(734,039)	**$ 3,785,388**	$3,565,337	$ 68,788	$ 497,556	$(446,991)	**$3,684,690**
LIABILITIES AND SHAREHOLDERS' EQUITY										
Current liabilities:										
Accounts payable and accrued liabilities	$ 204,295	$ 2,189	$ 46,512	$ (796)	**$ 252,200**	$ 238,935	$ 6,825	$ 39,122	$ (580)	**$ 284,302**
Current portion of long-term debt	287,092	—	—	—	**287,092**	156,678	—	—	—	**156,678**
Note payable to parent	—	—	250,183	(250,183)	**—**	—	—	135,529	(135,529)	**—**
Other current liabilities	80,328	36	9,718	—	**90,082**	86,633	64	7,343	—	**94,040**
Total current liabilities	571,715	2,225	306,413	(250,979)	**629,374**	482,246	6,889	181,994	(136,109)	**535,020**
Long-term debt	1,582,280	—	—	—	**1,582,280**	1,865,836	—	—	—	**1,865,836**
Other liabilities	122,390	2,119	38,878	—	**163,387**	121,869	769	35,158	—	**157,796**
Deferred income taxes	577	67,365	35,906	(46,288)	**57,560**	16,232	4,446	28,664	(2,458)	**46,884**
Total liabilities	2,276,962	71,709	381,197	(297,267)	**2,432,601**	2,486,183	12,104	245,816	(138,567)	**2,605,536**
Shareholders' equity	1,352,787	137,329	299,443	(436,772)	**1,352,787**	1,079,154	56,684	251,740	(308,424)	**1,079,154**
	$3,629,749	$ 209,038	$ 680,640	$(734,039)	**$ 3,785,388**	$3,565,337	$ 68,788	$ 497,556	$(446,991)	**$3,684,690**

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(In Thousands)

	Year Ended December 31,														
	2010					2009					2008				
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues															
Oil, natural gas, and NGL sales	$ 479,250	$225,937	$148,552	$ —	**$ 853,739**	$ 520,792	$ 132,644	$ 114,394	$ —	**$ 767,830**	$ 1,128,110	$109,094	$ 409,967	$ —	**$ 1,647,171**
Interest and other	5,504	32	23	(4,547)	**1,012**	17,666	92	(174)	(16,959)	**625**	19,908	430	340	(17,089)	**3,589**
Equity earnings in subsidiaries	135,943	—	—	(135,943)	**—**	(244,758)	—	—	244,758	**—**	(112,817)	—	—	112,817	**—**
Total revenues	620,697	225,969	148,575	(140,490)	**854,751**	293,700	132,736	114,220	227,799	**768,455**	1,035,201	109,524	410,307	95,728	**1,650,760**
Costs, expenses, and other:															
Lease operating expenses	79,927	11,974	26,173	—	**118,074**	99,459	19,259	28,259	—	**146,977**	108,680	14,422	44,728	—	**167,830**
Other direct operating costs	47,028	11,454	11,577	—	**70,059**	48,970	6,023	8,825	—	**63,818**	75,493	8,180	17,946	—	**101,619**
General and administrative	61,174	2,408	9,622	—	**73,204**	60,282	2,506	8,288	—	**71,076**	64,826	336	9,570	—	**74,732**
Depreciation, depletion, and amortization	130,777	55,642	65,199	—	**251,618**	197,501	47,637	58,484	—	**303,622**	361,443	25,780	144,958	—	**532,181**
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	142,567	1,381	10,122	(4,547)	**149,523**	147,330	12,256	20,456	(16,555)	**163,487**	111,316	—	31,452	(17,089)	**125,679**
Realized and unrealized (gains) losses on derivative instruments, net	(122,389)	(27,457)	(286)	—	**(150,132)**	(111,765)	(20,062)	(321)	—	**(132,148)**	(75,236)	(53,769)	(36,524)	—	**(165,529)**
Gain on sale of assets	—	—	—	—	**—**	—	—	—	—	**—**	—	—	(21,063)	—	**(21,063)**
Other, net	780	(456)	(6,067)	—	**(5,743)**	18,433	260	(9,305)	—	**9,388**	46,726	600	19,655	276	**67,257**
Total costs, expenses, and other	339,864	54,946	116,340	(4,547)	**506,603**	1,615,987	286,446	316,185	(16,555)	**2,202,063**	2,575,056	29,564	663,954	(16,813)	**3,251,761**
Earnings (loss) before income taxes	280,833	171,023	32,235	(135,943)	**348,148**	(1,322,287)	(153,710)	(201,965)	244,354	**(1,433,608)**	(1,539,855)	79,960	(253,647)	112,541	**(1,601,001)**
Income tax	53,312	62,919	4,396	—	**120,627**	(399,154)	(56,937)	(54,384)	—	**(510,475)**	(513,532)	28,586	(89,732)	—	**(574,678)**
Net earnings (loss)	$ 227,521	$108,104	$ 27,839	$(135,943)	**$ 227,521**	$ (923,133)	$ (96,773)	$(147,581)	$244,354	**$ (923,133)**	$(1,026,323)	$ 51,374	$(163,915)	$112,541	**$(1,026,323)**

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

(In Thousands)

	Year Ended December 31,											
	2010				2009				2008			
	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)	$ 91,578	$ 108,104	$ 27,839	**$ 227,521**	$ (678,375)	$ (96,773)	$(147,985)	**$ (923,133)**	$ (913,506)	$ 51,374	$(164,191)	**$(1,026,323)**
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:												
Depreciation, depletion, and amortization	130,777	55,642	65,199	**251,618**	197,501	47,637	58,484	**303,622**	361,443	25,780	144,958	**532,181**
Unrealized (gains) losses on derivative instruments, net	(33,602)	(4,274)	(44)	**(37,920)**	146,628	28,929	461	**176,018**	(110,904)	(69,091)	(41,495)	**(221,490)**
Deferred income tax	67,212	62,919	4,397	**134,528**	(469,969)	(56,937)	(54,384)	**(581,290)**	(521,281)	28,586	(93,122)	**(585,817)**
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	29,936	263	(15,063)	**15,136**	33,387	334	(18,505)	**15,216**	53,485	180	1,019	**54,684**
Changes in operating assets and liabilities:												
Accounts receivable	29,833	(25,805)	(11,803)	**(7,775)**	27,084	(2,403)	11,109	**35,790**	20,872	3,709	18,273	**42,854**
Other current assets	21,297	42	(747)	**20,592**	34,239	(364)	(3,066)	**30,809**	(78,166)	56	(2,104)	**(80,214)**
Accounts payable and accrued liabilities	(60,768)	(2,557)	483	**(62,842)**	(22,322)	(7,984)	(17,650)	**(47,956)**	(3,532)	4,859	14,469	**15,796**
Accrued interest and other current liabilities	(17,023)	(191)	9,285	**(7,929)**	15,344	(1,571)	(1,696)	**12,077**	(30,258)	(549)	121	**(30,686)**
Net cash provided by operating activities	259,240	194,143	79,546	**532,929**	439,294	129,435	28,267	**596,996**	659,961	78,919	331,160	**1,070,040**
Investing activities:												
Capital expenditures for property and equipment	(432,484)	(121,458)	(253,836)	**(807,778)**	(456,959)	(104,218)	(107,541)	**(668,718)**	(1,828,225)	(124,247)	(452,021)	**(2,404,493)**
Proceeds from sales of assets	140,643	(1,565)	27,491	**166,569**	657,247	276,211	120,604	**1,054,062**	284,677	—	25,263	**309,940**
Other, net	—	—	—	**—**	27	—	1	**28**	933	(4)	131	**1,060**
Net cash (used) provided by investing activities	(291,841)	(123,023)	(226,345)	**(641,209)**	200,315	171,993	13,064	**385,372**	(1,542,615)	(124,251)	(426,627)	**(2,093,493)**
Financing activities:												
Proceeds from bank borrowings	—	—	146,726	**146,726**	747,000	—	121,533	**868,533**	2,847,000	—	356,360	**3,203,360**
Repayments of bank borrowings	—	—	(146,726)	**(146,726)**	(1,937,000)	—	(236,687)	**(2,173,687)**	(1,822,000)	—	(373,101)	**(2,195,101)**
Issuance of senior notes, net of issuance costs	—	—	—	**—**	559,767	—	—	**559,767**	247,188	—	—	**247,188**
Proceeds from common stock offering, net of offering costs	—	—	—	**—**	256,217	—	—	**256,217**	—	—	—	**—**
Redemption and repurchase of notes	(152,038)	—	—	**(152,038)**	(970)	—	—	**(970)**	(269,710)	—	—	**(269,710)**
Net activity in investments of subsidiaries	(67,043)	(70,162)	137,205	**—**	213,865	(298,004)	84,139	**—**	(147,079)	42,755	104,324	**—**
Other, net	11,284	(1,334)	1,569	**11,519**	(22,736)	(3,119)	(869)	**(26,724)**	27,292	2,265	964	**30,521**
Net cash (used) provided by financing activities	(207,797)	(71,496)	138,774	**(140,519)**	(183,857)	(301,123)	(31,884)	**(516,864)**	882,691	45,020	88,547	**1,016,258**
Effect of exchange rate changes on cash	—	—	(277)	**(277)**	—	—	(488)	**(488)**	—	—	(285)	**(285)**
Net (decrease) increase in cash and cash equivalents	(240,398)	(376)	(8,302)	**(249,076)**	455,752	305	8,959	**465,016**	37	(312)	(7,205)	**(7,480)**
Cash and cash equivalents at beginning of period	456,978	379	9,864	**467,221**	1,226	74	905	**2,205**	1,189	386	8,110	**9,685**
Cash and cash equivalents at end of period	$ 216,580	$ 3	$ 1,562	**$ 218,145**	$ 456,978	$ 379	$ 9,864	**$ 467,221**	$ 1,226	$ 74	$ 905	**$ 2,205**

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

Estimated Proved Oil and Gas Reserves

The reserve estimates as of December 31, 2010 and 2009 presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance issued by the Financial Accounting Standards Board 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 "Modernization of Oil and Gas Reporting" rule, which was also effective for annual reports for fiscal years ending on or after December 31, 2009.

The above-mentioned 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, 2010 and 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 authoritative 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. Data prior to December 31, 2009 presented throughout this footnote is not required to be, nor has it been, updated based on the new guidance.

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 2010 and 2009 and the year-end spot price for oil and gas for 2008, 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.

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.

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.

The following table sets forth the Company's estimates of its net proved, net proved developed, and net proved undeveloped oil and gas reserves as of December 31, 2010, 2009, and 2008 and changes in its net proved oil and gas reserves for the years then ended. For the years presented, the Company engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services.

	Oil (MBbls)				Natural Gas Liquids (MBbls)				Natural Gas (MMcf)				
	United States	Canada	Italy	Total	United States	Canada	Italy	Total	United States	Canada	Italy	Total	Total MMcfe
Balance at January 1, 2008	50,056	6,219	—	56,275	37,101	1,100	—	38,201	1,287,870	208,198	56,308	1,552,376	2,119,232
Revisions of previous estimates	(6,107)	(1,839)	—	(7,946)	(6,548)	346	—	(6,202)	(129,633)	1,813	—	(127,820)	(212,708)
Extensions and discoveries	6,384	3,781	—	10,165	11,187	331	—	11,518	351,628	50,817	—	402,445	532,543
Production	(3,778)	(802)	—	(4,580)	(3,151)	(300)	—	(3,451)	(118,120)	(23,313)	—	(141,433)	(189,619)
Sales of reserves in place	(2,992)	—	—	(2,992)	(892)	—	—	(892)	(69,554)	—	—	(69,554)	(92,858)
Purchases of reserves in place	6,622	—	—	6,622	12,402	—	—	12,402	397,392	—	—	397,392	511,536
Balance at December 31, 2008	50,185	7,359	—	57,544	50,099	1,477	—	51,576	1,719,583	237,515	56,308	2,013,406	2,668,126
Revisions of previous estimates	1,596	2,220	—	3,816	(5,229)	594	—	(4,635)	(357,352)	(33,020)	(4,570)	(394,942)	(399,856)
Extensions and discoveries	22,324	6,725	—	29,049	9,156	495	—	9,651	320,705	110,299	—	431,004	663,204
Production	(3,397)	(626)	—	(4,023)	(3,012)	(230)	—	(3,242)	(116,029)	(23,248)	—	(139,277)	(182,867)
Sales of reserves in place	(53,776)	(314)	—	(54,090)	(12,778)	(846)	—	(13,624)	(151,476)	(70,345)	—	(221,821)	(628,105)
Purchases of reserves in place	—	—	—	—	—	—	—	—	—	—	—	—	—
Balance at December 31, 2009	16,932	15,364	—	32,296	38,236	1,490	—	39,726	1,415,431	221,201	51,738	1,688,370	2,120,502
Revisions of previous estimates	1,276	166	—	1,442	(278)	32	—	(246)	(38,515)	(7,597)	—	(46,112)	(38,936)
Extensions and discoveries	4,591	2,746	—	7,337	9,051	26	—	9,077	199,790	86,028	—	285,818	384,302
Production	(2,357)	(828)	—	(3,185)	(3,589)	(134)	—	(3,723)	(101,346)	(22,436)	—	(123,782)	(165,230)
Sales of reserves in place	(183)	(163)	—	(346)	(292)	(439)	—	(731)	(45,783)	(10,183)	—	(55,966)	(62,428)
Purchases of reserves in place	59	—	—	59	256	—	—	256	4,154	—	—	4,154	6,044
Balance at December 31, 2010	20,318	17,285	—	37,603	43,384	975	—	44,359	1,433,731	267,013	51,738	1,752,482	2,244,254
Proved developed reserves at:													
January 1, 2008	36,999	4,094	—	41,093	24,651	853	—	25,504	900,483	163,438	28,154	1,092,075	1,491,657
December 31, 2008	34,298	4,652	—	38,950	29,716	1,175	—	30,891	1,039,586	192,338	28,154	1,260,078	1,679,124
December 31, 2009	11,327	5,012	—	16,339	23,037	1,190	—	24,227	916,005	169,740	—	1,085,745	1,329,141
December 31, 2010	13,421	5,821	—	19,242	24,120	773	—	24,893	886,644	169,292	25,869	1,081,805	1,346,615
Proved undeveloped reserves at:													
January 1, 2008	13,057	2,125	—	15,182	12,450	247	—	12,697	387,387	44,760	28,154	460,301	627,575
December 31, 2008	15,887	2,707	—	18,594	20,383	302	—	20,685	679,997	45,177	28,154	753,328	989,002
December 31, 2009	5,605	10,352	—	15,957	15,199	300	—	15,499	499,426	51,461	51,738	602,625	791,361
December 31, 2010	6,897	11,464	—	18,361	19,264	202	—	19,466	547,087	97,721	25,869	670,677	897,639

Revisions of previous estimates

In 2010, negative revisions of 39 Bcfe were primarily the result of performance in existing producing wells. In 2009 and 2008, the net negative revisions of 400 Bcfe and 213 Bcfe, respectively, were due to a decrease in the natural gas price used to estimate reserve volumes for each period and, in 2008, due to a decrease in the oil price used to estimate reserve volumes.

Extensions and discoveries

In 2010, the Company had a total of 384 Bcfe of extensions and discoveries, which were primarily due to successful drilling results in the Texas Panhandle, North Louisiana, and the Western Canadian Sedimentary Basin. In 2009 and 2008, the Company had 663 Bcfe and 533 Bcfe, respectively, of extensions and discoveries, which were primarily due to successful drilling results in the Texas Panhandle, East Texas / North Louisiana, and the Western Canadian Sedimentary Basin.

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

Sales of reserves in place

Sales of reserves in place for each of the years presented in the table above represent the sale of non-core oil and gas property interests. See Note 2 for a description of these sales.

Purchase of reserves in place

In 2008, the Company acquired producing oil and natural gas properties located in the Texas Panhandle and in East Texas / North Louisiana. See Note 2 for a description of these acquisitions.

Aggregate Capitalized Costs

The aggregate capitalized costs relating to oil and gas producing activities were as follows as of the dates indicated:

	December 31,		
	2010	2009	2008
		(In Thousands)	
Costs related to proved properties	$ 9,663,953	$ 8,828,373	$ 8,952,292
Costs related to unproved properties	751,784	828,645	964,027
	10,415,737	9,657,018	9,916,319
Less accumulated depletion	(7,813,494)	(7,511,661)	(5,502,782)
	$ 2,602,243	$ 2,145,357	$ 4,413,537

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

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, 2010, 2009, and 2008:

	United States	Canada	Italy	Total
		(In Thousands)		
2010				
Property acquisition costs:				
Proved properties	$ 5,823	$ —	$ —	$ 5,823
Unproved properties	64,593	38,685	—	103,278
Exploration costs	190,553	9,329	2,386	202,268
Development costs	319,510	155,017	317	474,844
Total costs incurred[1]	$ 580,479	$203,031	$2,703	$ 786,213
2009				
Property acquisition costs:				
Proved properties	$ —	$ —	$ —	$ —
Unproved properties	45,230	11,428	—	56,658
Exploration costs	112,919	25,428	7,578	145,925
Development costs	339,826	51,422	—	391,248
Total costs incurred[1]	$ 497,975	$ 88,278	$7,578	$ 593,831
2008				
Property acquisition costs:				
Proved properties	$ 804,616	$ —	$ —	$ 804,616
Unproved properties	616,436	6,880	—	623,316
Exploration costs	244,127	44,748	3,157	292,032
Development costs	895,761	146,325	709	1,042,795
Total costs incurred[1]	$2,560,940	$197,953	$3,866	$2,762,759

(1) Includes amounts relating to changes in estimated asset retirement obligations of $(2.1) million, $2.9 million, and $15.0 million recorded in the years ended December 31, 2010, 2009, and 2008, respectively.

(16) 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, 2010, 2009, and 2008 are presented below.

	United States	Canada	Italy	Total
	(In Thousands, except per Mcfe amounts)			
2010				
Oil and gas sales	$ 707,692	$ 146,047	$ —	$ 853,739
Expenses:				
Production expense	149,292	38,841	—	188,133
Depletion expense	179,656	62,846	—	242,502
Accretion of asset retirement obligations	6,057	1,036	41	7,134
Income tax	134,801	12,138	—	146,939
Total expenses	469,806	114,861	41	584,708
Results of operations from oil and gas producing activities	$ 237,886	$ 31,186	$(41)	$ 269,031
Depletion rate per Mcfe	$ 1.31	$ 2.23	$ —	$ 1.47
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 expense	(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

(16) 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, 2010			
	United States	Canada	Italy	Total
	(In Thousands)			
Future oil and gas sales	$ 9,029,839	$2,436,765	$ 904,902	$12,371,506
Future production costs	(2,546,332)	(552,215)	(192,013)	(3,290,560)
Future development costs	(1,462,832)	(438,761)	(17,100)	(1,918,693)
Future income taxes	(860,047)	(314,449)	(260,541)	(1,435,037)
Future net cash flows	4,160,628	1,131,340	435,248	5,727,216
10% annual discount for estimated timing of cash flows	(2,195,708)	(582,732)	(229,722)	(3,008,162)
Standardized measure of discounted future net cash flows	$ 1,964,920	$ 548,608	$ 205,526	$ 2,719,054

	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

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

	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

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, 2010			
	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	$1,328,889	$ 498,690	$225,420	$2,052,999
Changes resulting from:				
Sales of oil and gas, net of production costs	(558,400)	(107,206)	—	(665,606)
Net changes in prices and future production costs	603,003	58,633	2,040	663,676
Net changes in future development costs	(29,183)	(473)	17,586	(12,070)
Extensions, discoveries, and improved recovery	445,546	114,062	—	559,608
Development costs incurred during the period	134,451	36,112	—	170,563
Revisions of previous quantity estimates	48,960	(15,076)	—	33,884
Changes in production rates, timing, and other	115,768	(55,413)	(65,068)	(4,713)
Sales of reserves in place	(34,108)	(15,565)	—	(49,673)
Purchases of reserves in place	6,530	—	—	6,530
Accretion of discount on reserves at beginning of year	139,179	61,380	33,175	233,734
Net change in income taxes	(235,715)	(26,536)	(7,627)	(269,878)
Total change for year	636,031	49,918	(19,894)	666,055
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$1,964,920	$ 548,608	$205,526	$2,719,054

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2010 was based on average prices and year-end costs. The Henry Hub average natural gas price and West Texas Intermediate ("WTI") average oil price during

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

the twelve-month period prior to December 31, 2010 were $4.38 per MMBtu and $79.81 per barrel, respectively.

	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

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

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

Henry Hub average natural gas price and 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 Henry Hub spot natural gas price and WTI spot price at December 31, 2008 were $5.71 per MMBtu and $44.60 per barrel, 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 Exchange Act, as of the end of the period covered by this Annual Report on Form 10-K (the "Evaluation Date"). Based on this evaluation, they believe that as of the Evaluation Date our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (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 Control Over Financial Reporting.

There has not been any change in our internal control over financial reporting that occurred during our quarterly period ended December 31, 2010 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, 2010. The effectiveness of our internal control over financial reporting as of December 31, 2010 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 and subsidiaries' internal control over financial reporting as of December 31, 2010, 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 and subsidiaries' 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 and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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 and subsidiaries as of December 31, 2010 and 2009 and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2010 and our report dated February 23, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
February 23, 2011

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, 2010 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 Exchange Act 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, 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, 2010 and 2009
3. Consolidated Statements of Operations—Years Ended December 31, 2010, 2009, and 2008
4. Consolidated Statements of Shareholders' Equity—Years Ended December 31, 2010, 2009, and 2008
5. Consolidated Statements of Cash Flows—Years Ended December 31, 2010, 2009, and 2008
6. Notes to Consolidated Financial Statements—Years Ended December 31, 2010, 2009, and 2008

(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).
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).

Exhibit Number	Description
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).
10.18*	Amendment No. 2 to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 12, 2010 (File No. 001-13515).

Exhibit Number	Description
10.19*	Amendment No. 3 to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1to Form 8-K for Forest Oil Corporation dated February 18, 2011 (File No. 001-13515).
10.20*	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).
10.21*	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).
10.22*	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).
10.23*	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).
10.24*	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).
10.25*	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).
10.26*	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).
10.27*	Form of Performance Unit Award Agreement (US) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 21, 2010 (File No. 001-13515).
10.28*	Form of Performance Unit Award Agreement (Canada) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated May 21, 2010 (File No. 001-13515).
10.29*	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).
10.30*	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).
10.31*	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).
10.32*	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).
10.33*	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).

Exhibit Number	Description
10.34*	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).
10.35*	Severance Agreement, dated as of December 1, 2009, by and between Victor A. Wind and Forest Oil Corporation, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation dated May 11, 2010 (File No. 001-13515)
10.36*	Form of 2010 Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2010 (File No. 001-13515).
10.37*	Form of 2010 Severance Agreement for Vice President, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2010 (File No. 001-13515).
10.38*	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).
10.39*	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).
10.40*	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).
10.41*	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).
10.42*	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).
10.43*	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).
10.44*	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).
10.45*	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).
10.46*	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).
10.47*	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).

Exhibit Number	Description
10.48*	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).
10.49*	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).
10.50*†	Second Amendment to Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008).
10.51	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).
10.52	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).
10.53	Forest Oil Corporation 2010 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated February 18, 2010 (File No. 001-13515).
10.54	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).
10.55	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).
10.56	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).
10.57	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).
10.58	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).
10.59	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).
10.60	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).
10.61	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).

Exhibit Number	Description
10.62	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).
10.63	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).
21.1†	List of Subsidiaries of Registrant.
23.1†	Consent of Ernst & Young LLP.
23.2†	Consent of DeGolyer and MacNaughton.
24.1†	Powers of Attorney (included on the signature pages hereof).
31.1†	Certification of Principal Executive Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
31.2†	Certification of Principal Financial Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of Chief Executive Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.
32.2**	Certification of Chief Financial Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.
99.1†	Reserves Audit Report (U.S. Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
99.2†	Reserves Audit Report (Canadian Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
99.3†	Reserves Audit Report (Italian Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
101.INS‡	XBRL Instance Document.
101.SCH‡	XBRL Taxonomy Extension Schema Document.
101.CAL‡	XBRL Taxonomy Calculation Linkbase Document.
101.LAB‡	XBRL Label Linkbase Document.
101.PRE‡	XBRL Presentation Linkbase Document.
101.DEF‡	XBRL Treasury Extension Definition

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

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

† Indicates Exhibits filed with this 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 of 1933, are deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, 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 23, 2011

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, 2010, 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 23, 2011
/s/ MICHAEL N. KENNEDY Michael N. Kennedy	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2011
/s/ VICTOR A. WIND Victor A. Wind	Senior Vice President, Chief Accounting Officer and Corporate Controller (Principal Accounting Officer)	February 23, 2011
/s/ JAMES D. LIGHTNER James D. Lightner	Chairman of the Board	February 23, 2011
/s/ LOREN K. CARROLL Loren K. Carroll	Director	February 23, 2011
/s/ DOD. A. FRASER Dod. A. Fraser	Director	February 23, 2011
/s/ JAMES H. LEE James H. Lee	Director	February 23, 2011
/s/ PATRICK R. MCDONALD Patrick R. McDonald	Director	February 23, 2011
/s/ RAYMOND I. WILCOX Raymond I. Wilcox	Director	February 23, 2011

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*	Amendment No. 2 to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 12, 2010 (File No. 001-13515).
10.19*	Amendment No. 3 to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1to Form 8-K for Forest Oil Corporation dated February 18, 2011 (File No. 001-13515).
10.20*	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).
10.21*	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).
10.22*	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).
10.23*	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).
10.24*	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).
10.25*	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).
10.26*	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).
10.27*	Form of Performance Unit Award Agreement (US) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 21, 2010 (File No. 001-13515).
10.28*	Form of Performance Unit Award Agreement (Canada) pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, as amended, incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated May 21, 2010 (File No. 001-13515).
10.29*	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).
10.30*	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).
10.31*	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).

Exhibit Number	Description
10.32*	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).
10.33*	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).
10.34*	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).
10.35*	Severance Agreement, dated as of December 1, 2009, by and between Victor A. Wind and Forest Oil Corporation, incorporated herein by reference to Exhibit 10.5 to Form 8-K for Forest Oil Corporation dated May 11, 2010 (File No. 001-13515).
10.36*	Form of 2010 Severance Agreement for Senior Vice President, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2010 (File No. 001-13515).
10.37*	Form of 2010 Severance Agreement for Vice President, incorporated herein by reference to Exhibit 10.2 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2010 (File No. 001-13515).
10.38*	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).
10.39*	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).
10.40*	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).
10.41*	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).
10.42*	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).
10.43*	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).
10.44*	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).
10.45*	Forest Oil Corporation Amended and Restated 2005 Salary Deferred Compensation Plan, effective as of December 31, 2004, incorporated herein by reference to Exhibit 10.21 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2005 (File No. 001-13515).

Exhibit Number	Description
10.46*	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).
10.47*	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).
10.48*	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).
10.49*	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).
10.50*†	Second Amendment to Forest Oil Corporation Executive Deferred Compensation Plan (as Amended and Restated, effective as of December 1, 2008).
10.51	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).
10.52	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).
10.53	Forest Oil Corporation 2010 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated February 18, 2010 (File No. 001-13515).
10.54	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).
10.55	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).
10.56	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).
10.57	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).
10.58	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).

Exhibit Number	Description
10.59	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).
10.60	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).
10.61	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).
10.62	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).
10.63	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).
21.1†	List of Subsidiaries of Registrant.
23.1†	Consent of Ernst & Young LLP.
23.2†	Consent of DeGolyer and MacNaughton.
24.1†	Powers of Attorney (included on the signature pages hereof).
31.1†	Certification of Principal Executive Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
31.2†	Certification of Principal Financial Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of Chief Executive Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.
32.2**	Certification of Chief Financial Officer of Forest Oil Corporation pursuant to 18 U.S.C. §1350.
99.1†	Reserves Audit Report (U.S. Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
99.2†	Reserves Audit Report (Canadian Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
99.3†	Reserves Audit Report (Italian Reserves) of DeGolyer and MacNaughton, independent petroleum engineering consulting firm, dated January 20, 2011.
101.INS‡	XBRL Instance Document.
101.SCH‡	XBRL Taxonomy Extension Schema Document.
101.CAL‡	XBRL Taxonomy Calculation Linkbase Document.
101.LAB‡	XBRL Label Linkbase Document.
101.PRE‡	XBRL Presentation Linkbase Document.
101.DEF‡	XBRL Treasury Extension Definition

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

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

† Indicates Exhibits filed with this 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 of 1933, are deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise, are not subject to liability under these sections.

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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 11, 2011 at 9:00 a.m. (MDT)

NON-GAAP FINANCIAL MEASURES

ADJUSTED EBITDA

In addition to reporting net earnings (loss) as defined under Generally Accepted Accounting Principles (GAAP), Forest also presented adjusted EBITDA, which is a non-GAAP performance measure. Adjusted EBITDA consists of net earnings (loss) before interest, income 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 (loss) (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 the items described above, 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 uses adjusted EBITDA to manage its business, including in preparing its annual operating budget and financial projections. 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 net 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 net 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's 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 before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. Forest's management uses adjusted discretionary cash flow to manage its business, including in preparing its annual operating budget and financial projections. This measure does not represent the residual cash flow available for discretionary expenditures. 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 2010 10-K for our reconciliation of non-GAAP financial measures to the most comparable GAAP measures.

Drill Bit Reserve Replacement Ratio

The drill bit reserve replacement ratio, including revisions, of 209% was calculated by dividing extensions and discoveries of 384 Bcfe less revisions of 39 Bcfe, by net sales volumes of 165 Bcfe.

Drill Bit F&D Costs

The drill bit finding and development costs, including revisions, of $1.90 per Mcfe were calculated by dividing the sum of total exploration and development expenditures (excluding asset retirement obligations, capitalized interest, and capitalized equity compensation), $656 million, by extensions and discoveries of 384 Bcfe less revisions of 39 Bcfe.

All-Sources Reserve Replacement Ratio

All-sources reserve replacement ratio of 213% was calculated by dividing reserves attributable to properties purchased during the year plus extensions and discoveries (which together total 390 Bcfe) less revisions of 39 Bcfe, by net sales volumes of 165 Bcfe.

All-Sources F&D Costs

All-sources finding and development costs of $2.18 per Mcfe were calculated by dividing the sum of total costs from capital activities (excluding asset retirement obligations, capitalized interest, and capitalized equity compensation), $765 million, by reserves attributable to properties purchased during the year plus extensions and discoveries (which together total 390 Bcfe) less revisions of 39 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 2010 10-K for additional disclosures.

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