FOREST OIL CORP
Form 8-K
September 12, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of report (Date of earliest event reported): **September 11, 2012**

FOREST OIL CORPORATION

(Exact name of registrant as specified in its charter)

New York

(State or other jurisdiction of incorporation)

1-13515 (Commission File Number)	**25-0484900** (IRS Employer Identification No.)
707 17th Street, Suite 3600, Denver, Colorado (Address of principal executive offices)	**80202** (Zip Code)

303.812.1400

(Registrant s telephone number, including area code)

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 5.02. Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangement of Certain Officers.

On September 11, 2012, the Board of Directors of Forest Oil Corporation appointed Patrick R. McDonald as Forest s permanent President and Chief Executive Officer, to serve in such capacity, subject to the provisions of Forest s Bylaws, until the next annual election of officers of Forest, or until his successor shall have been duly elected and qualified, or his earlier death, resignation or removal. Mr. McDonald has been a Forest director since 2004, and has been serving as our interim Chief Executive Officer since June of this year. Until his appointment as interim Chief Executive Officer, Mr. McDonald was a member of the Board s Audit Committee and served as chairman of the Board s Compensation Committee. Mr. McDonald was not appointed to his new position pursuant to any arrangement or understanding between him and any other person. He has no family relationship with any other person serving as a director or executive officer of Forest. Since the beginning of our last fiscal year there has been no transaction, and there currently is no transaction proposed, in an amount exceeding $120,000 and in which Mr. McDonald has an interest. Mr. McDonald is 55 years old.

Mr. McDonald served as Chief Executive Officer, President and Director of Carbon Natural Gas Company, an oil and gas exploration company and its predecessor, Nytis USA, since 2004, and has served as Chairman of Carbon Natural Gas Company since 2011. He also serves as non-executive chairman of the board of Lone Pine Resources Inc., an oil and gas exploration and production company, where he was elected as a director in March 2011. From 1998 to 2003, Mr. McDonald served as President, Chief Executive Officer, and Director of Carbon Energy Corporation, an oil and gas exploration and production company. From 1987 to 1997, he served as 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. He is a Certified Petroleum Geologist and is a member of the American Association of Petroleum Geologists and Canadian Society of Petroleum Geologists.

The financial terms of Mr. McDonald s service as our President and Chief Executive Officer have not yet been determined. Such terms will be disclosed on a subsequent Form 8-K when they have been finalized.

Item 7.01. Regulation FD Disclosure.

(a) On September 12, 2012, Forest posted a new investor presentation on its website www.forestoil.com.

(b) On September 12, 2012, Forest issued a press release announcing the appointment of Patrick R. McDonald as the new President and Chief Executive Officer. A copy of the press release is filed as Exhibit 99.1 to this Current Report on Form 8-K.

(c) Also on September 12, 2012, Forest issued a press release that, among other things, updates our guidance for the remainder of 2012. A copy of the press release is filed as Exhibit 99.2 to this Current Report on Form 8-K.

(d) Finally, Forest also issued a press release on September 12, 2012, announcing the commencement of a private offering to eligible purchasers, subject to market and other conditions, of $300,000,000 in aggregate principal amount of a new series of senior notes due 2020 (the Notes). A copy of the press release is filed as Exhibit 99.3 to this Current Report on Form 8-K and is incorporated herein by reference.

The Notes will not be registered under the Securities Act of 1933, as amended (the Securities Act), or applicable state securities laws and may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements of the Securities Act and applicable state securities laws. The Notes may be resold by the initial purchasers pursuant to Rule 144A and Regulation S under the Securities Act. The information contained in this Current Report on Form 8-K, including Exhibit 99.3, is neither an offer to sell nor a solicitation of an offer to buy any of the securities in the offering or any other securities of Forest.

The information in this Item 7.01 to this Current Report on Form 8-K, including Exhibits 99.1, 99.2 and 99.3, shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section or Sections 11 and 12(a)(2) of the Securities Act of 1933, as amended.

Item 8.01. Other Events.

In connection with the commencement of the private offering of the Notes, we are providing updated disclosures with respect to us, our business strategy, and recent developments, and updating certain disclosures appearing under the headings Risk Factors contained in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011 and our quarterly reports on Form 10-Q for the periods ending March 31, 2012 and June 30, 2012, and risks described in our Current Reports on Form 8-K.

The information in this Item 8.01, includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. Forwardlooking statements are statements other than statements of historical facts or present facts that address activities, events, outcomes, and other matters that we plan, expect, intend, assume, believe, budget, predict, forecast, project, estimate, or anticipate (and other similar expressions) will, should, or may occur in the future. Generally, the words expects, anticipates, targets, goals, projects, intend plans, believes, seeks, estimates, will, could, should, future, potential, continue, the negative of such words or other variation and similar expressions identify forward-looking statements, and any statements regarding our future financial condition, results of operations, and business are also forward-looking statements. Similarly, statements that describe our strategies, initiatives, objectives, plans, or goals are forward-looking. These forward-looking statements are based on our current intent, belief, expectations, estimates, projections, forecasts, and assumptions about future events and are based on currently available information as to the outcome and timing of future events. These statements are not guarantees of future performance.

(i) Forest Oil Corporation

We are 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. We currently conduct our operations in one reportable geographic segment, which is the United States. We also have oil and gas exploration activities in Italy and South Africa. Our core operational areas are in the Texas Panhandle Area, the Eagle Ford Shale in South Texas, and the East Texas / North Louisiana Area.

Our total estimated proved oil and natural gas reserves as of December 31, 2011 were approximately 1,904 billion cubic feet equivalent (Bcfe). In the first quarter of 2012, we determined that we could no longer conclude with reasonable certainty that our Italian natural gas reserves of 51.7 Bcfe were producible and, therefore, we concluded that such reserves could no longer be classified as proved reserves. See Risk Factors Our estimates of oil and natural gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves and our financial condition. below for more information relating to our estimated proved reserves.

In June 2011, we completed an initial public offering of approximately 18% of the common stock of our then wholly owned subsidiary, Lone Pine Resources Inc. (Lone Pine), which held our ownership interests in our Canadian operations. On September 30, 2011, we distributed, or spun-off, our remaining 82% ownership in Lone Pine to our shareholders of record as of September 16, 2011, by means of a special stock dividend of Lone Pine common shares.

Our common stock trades on the New York Stock Exchange under the symbol FST. Our principal executive offices are located at 707 17th Street, Suite 3600, Denver, Colorado 80202, and our telephone number at that address is (303) 812-1400.

Strategy

Following the spin-off of Lone Pine, we implemented a long-term operating strategy intended to increase shareholder value through the achievement of organic growth while maintaining a capital expenditure budget that approximates cash flows from operating activities. We believe measured growth can be achieved through this strategy by focusing capital expenditures primarily on developing Forest s core operational areas located in the Texas Panhandle Area, the Eagle Ford Shale in South Texas, and the East Texas / North Louisiana Area. In addition, our growth may be supplemented from time to time through opportunistic acquisitions. We endeavor to execute this strategy as follows:

Exploit and develop resource plays for measured growth while maintaining a capital expenditure budget that approximates cash flows from operating activities. In our efforts to grow, 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 growth from our diverse portfolio of shale, unconventional and conventional oil and natural gas properties. Our core operational areas have a large number of remaining commodity-diverse drilling locations, providing what we believe are repeatable development opportunities. In 2012, due to a low natural gas price environment, we are devoting the majority of our exploration and development expenditures to oil and natural gas liquids projects, including approximately 40% in the Texas Panhandle Area and 30% in the Eagle Ford Shale. We developed our original 2012 capital expenditure budget using natural gas pricing assumptions that were higher than the actual prices we have realized during 2012. As a result, our capital expenditures have exceeded cash flows to date in 2012. However, we reduced our drilling rig program from nine rigs to five rigs and expect our capital expenditures to approximate cash flows in the fourth quarter of 2012.

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

Rationalize our asset base through property divestitures and acquisitions. In the near term, as economic conditions permit, we intend to divest certain non-core assets, focusing primarily on non-producing, non-reserve based assets that are not located in our core operational areas. Over the longer term, we intend to pursue property acquisitions to enhance existing business operations in our core operational areas.

Maintain financial flexibility. We intend to maintain a strong liquidity position to successfully execute our growth strategy through the application of budget controls and prudent financial management. Further, we intend to focus on reducing our debt levels relative to our estimated proved reserves and EBITDA, and we plan to consider divestitures and other means to increase our financial flexibility.

Core operational areas

Our core operational areas consist of a well-balanced portfolio of tight-gas sands, carbonates, and shale plays with multiple stacked-pay opportunities in the United States that have exposure to oil, natural gas, and natural gas liquids. We initially exploited the majority of our core operational areas through vertical development, but with the emergence of new drilling and completion technology, we have transitioned these plays to horizontal development.

Through the application of horizontal drilling, we seek to enhance initial production rates and estimated ultimate recoveries while focusing on reducing drilling costs. Our primary areas of focus in 2012 are in the Texas Panhandle Area, the Eagle Ford Shale in South Texas, and the East Texas / North Louisiana Area.

Texas Panhandle Area

We have approximately 109,000 net acres in the Texas Panhandle Area, establishing Forest as one of the top acreage holders in this area. The area provides for excellent horizontal drilling opportunities targeting multiple liquids-rich Granite Wash intervals as well as oil objectives including the Missourian Wash (Hogshooter), Cleveland, Tonkawa, and Douglas formations. We drilled our first Granite Wash 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, we increased our 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. In total, we have successfully developed seven liquids-rich intervals as prospective for horizontal development in the Granite Wash. 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. Additionally, during 2011 and 2012, Forest successfully developed seven prospective oil intervals, including the Missourian Wash formation, which expands the oil drilling potential within the Texas Panhandle Area. In total, we have developed 16 intervals as prospective for horizontal development in the Texas Panhandle Area. Forest initially planned to run a five rig drilling program during 2012, targeting the Granite Wash and other prospective intervals, including the Missourian Wash and other oil intervals. Due to the recent decline in the natural gas liquids market, we are currently reducing our drilling program to two rigs in the area, with a focus on developing the oil intervals.

Eagle Ford Shale

We have approximately 103,000 net acres in the Eagle Ford Shale, primarily located in Gonzales County in South Texas. The area provides us with access to the oil-bearing section of the Eagle Ford and is expected to yield an 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 2010 and expanded the program in 2011 to focus on the optimization of our development operations. This optimization included taking core samples, acquiring 3-D seismic, utilizing micro-seismic during horizontal well completions, and testing different sections of the Eagle Ford Shale, all with the goal of finding the optimal section in the Eagle Ford in which to land the lateral portion of our wells and the most effective and efficient methods to complete those wells. Through our optimization efforts undertaken in 2011 and based on our drilling in 2012, we believe that we can generate economic production rates and recoveries in this area. Currently, our drilling in the Eagle Ford Shale is focused in the central fairway of our acreage position, where we have experienced the most consistent results and have the largest, most contiguous block of acreage. We have initiated a development plan that employs a two rig drilling program in the area, which should allow us to hold approximately 40,000 acres over the next several years. We have identified approximately 500 total locations on this acreage position based on 80-acre spacing.

East Texas / North Louisiana Area

We have approximately 123,000 net acres in the East Texas / North Louisiana Area. The area provides for horizontal drilling opportunities targeting multiple stacked-pay intervals, including the Cotton Valley, Pettit, Haynesville, and other formations. In 2010, our development program was focused in the Haynesville Shale in North Louisiana, where we drilled 20 horizontal wells that had average 24-hour initial production rates of 16 million cubic feet equivalent per day (MMcfe/d). In an effort to optimize recovery from Haynesville Shale wells, Forest instituted a restricted flow rate production program in late-2010. Under this program, initial production rates from the last six wells in 2010 were curtailed at 11 to 15 MMcfe/d. In 2011, we reduced drilling and completions efforts in the Haynesville Shale in North Louisiana and the Cotton Valley in East Texas due to increasing service costs. By the end of 2011, we re-entered the play as a result of reductions in drilling and completion costs in the region and liquids-rich drilling opportunities in the Cotton Valley. We initially planned to run a two rig drilling program in the area during 2012, but we are currently reducing the program to one rig due to the recent decline in the natural gas liquids market.

(ii) **Recent Developments**

Appointment of President and Chief Executive Officer

On September 12, 2012, we announced that our board of directors has completed its executive search process and named Patrick R. McDonald as our President and Chief Executive Officer, effective immediately. Mr. McDonald has served as our Interim Chief Executive Officer since June 21, 2012.

Capital and drilling program for the second half of 2012

In the second half of 2012, we intend to fund our Eagle Ford Shale development program and reduce our overall capital spending rates by cutting capital from lower-return liquids projects in the East Texas Area and the Texas Panhandle Area. We entered the third quarter of 2012 operating nine drilling rigs and currently have reduced our drilling program to the following: two rigs in the Eagle Ford Shale, two rigs in the Texas Panhandle, targeting the Hogshooter and other oil intervals, and one rig in East Texas, targeting liquids intervals.

We estimate that our capital expenditures for the second half of 2012 will be between $240 million and $260 million (excluding capitalized interest, capitalized stock-based compensation, and asset retirement obligations incurred). In the first half of 2012, our total capital expenditures were $444 million ($433 million excluding capitalized interest, capitalized stock-based compensation, and asset retirement obligations incurred). Our current capital expenditure budget for the second half of 2012 represents an increase of $50 million, which is primarily related to a higher level of drilling activity than previously expected during July and August 2012. During the fourth quarter of 2012, we expect that our capital spending will be approximately equal to our expected cash flows based on current commodity prices. Our remaining 2012 capital budget mainly targets higher-margin oil opportunities, and we have reduced spending in, and expect to have lower production from, lower-return natural gas liquids and natural gas projects.

We believe that reducing our capital program was the first step in improving our financial strength and flexibility. We also intend to divest certain non-core assets, focusing primarily on non-producing, non-reserve based assets that are not located in our core operational areas. In our core areas where we have reduced capital spending, our acreage is held by production; therefore, we plan to return to those areas with a more aggressive development program when a more robust commodity price environment exists.

Operational update and other recent events

On September 12, 2012, we announced that for the second half of 2012, we expect our net sales volumes to average between approximately 330 MMcfe/d and 340 MMcfe/d (66% natural gas and 34% oil and natural gas liquids).

In the second quarter of 2012, we incurred a $349 million ceiling test write-down, and primarily in connection therewith, we recorded a $290 million valuation allowance on our deferred tax assets. We expect that we will incur an additional ceiling test write-down in the third quarter of 2012 that is similar in magnitude to our second quarter write-down. In addition, we expect to recognize a non-cash impairment charge of approximately $65 million in the third quarter of 2012 related to our operations in South Africa.

On August 10, 2012, we entered into an agreement to sell the majority of our East Texas natural gas gathering assets to a subsidiary of Tristate Midstream II, LLC for proceeds of $34 million. We can also earn up to $9 million of additional performance payments contingent on future activity. In conjunction with the sale, we entered into a ten-year natural gas gathering agreement with the buyer under which we will commit production from our existing and future operated wells located within five miles of the current configuration of the gathering system. The transaction is expected to close on October 31, 2012 and is subject to customary closing conditions and purchase price adjustments. We intend to use the net proceeds from the sale to repay a portion of the outstanding borrowings under our bank credit facility.

On August 28, 2012, we entered into an agreement to settle the litigation styled *Hilcorp Alaska, LLC (formerly Union Oil Company of California) v. Forest Oil Corporation*, Cause No. 3:10-cv-00269, in the United States District Court for the District of Alaska. Under the settlement agreement, we agreed to pay $7 million in return for a release of all claims that were or could have been asserted in the litigation and an indemnity covering claims for any past, present, or future costs or expenses associated with the Trading Bay Field, the Trading Bay Unit, and the Trading Bay Production Facility located in and near Cook Inlet, Alaska, including claims related to plugging and abandonment and platform decommissioning costs and environmental matters.

Natural gas, natural gas liquids, and oil derivatives

We periodically enter into commodity derivative instruments such as swap and collar agreements as an attempt to moderate the effects of wide fluctuations in commodity prices on our cash flows and to manage the exposure to commodity price risk. Since our last earnings release dated July 30, 2012, we have added 4 thousand barrels per day (MBbls/d) of calendar 2013 oil swaps at $95.53 per barrel.

As of September 12, 2012, we had natural gas, natural gas liquids, and oil derivatives in place for the last six months of 2012 and calendar year 2013 covering the aggregate average daily volumes and weighted average prices as follows:

		July - Dec 2012		2013
Natural gas swaps:				
Contract volumes (Bbtu/d)		155.0(1)		160.0
Weighted average price (per MMBtu)	$	4.63	$	3.98
Natural gas liquids swaps:				
Contract volumes (MBbls/d)		2.0		
Weighted average price (per Bbl)	$	45.22	$	
Oil swaps:				
Contract volumes (MBbls/d)		4.5		4.0
Weighted average price (per Bbl)	$	97.26	$	95.53

(1) 50 Bbtu/d of 2012 gas swaps (with a weighted average hedged price per MMBtu of $5.30) are layered with a written put of $3.53 and a call spread of $4.00 to $4.50. Together with the put and call spread, Forest will receive the swap price of $5.30 on the 50 Bbtu/d except as follows: Forest will receive (i) NYMEX Henry Hub (HH) plus $1.77 when NYMEX HH is below $3.53; (ii) $5.30 plus the value of the call spread when NYMEX HH is between $4.00 and $4.50; and (iii) $5.80 when NYMEX HH is $4.50 or above.

In connection with entering into certain 2012 gas swaps with premium hedged prices, Forest granted oil puts to the counterparties, giving the counterparties the option to put 5 MBbls/d to Forest at $75.00 per Bbl on a monthly basis during the period July 2012 through December 2012.

In connection with several swaps shown in the table above, we granted swaption instruments to counterparties in exchange for us receiving premium hedged prices on the swaps. The table below sets forth the outstanding swaptions as of September 12, 2012:

		2013		2014		2015
Natural gas swaptions:						
Contract volumes (Bbtu/d)		40.0				
Weighted average price (per MMBtu)	$	4.02	$		$	
Oil swaptions:						
Contract volumes (MBbls/d)		2.0		5.0		3.0
Weighted average price (per Bbl)	$	95.00	$	105.80	$	100.00

Proposed partial redemption of 2014 notes

Subject to closing the offering of the Notes, we intend to promptly call for redemption of 50% of the aggregate principal amount of our outstanding 81/2% Senior Notes due 2014 (the 2014 notes). The principal amount outstanding of the 2014 notes is $600 million. The redemption price for the 2014 notes is based on a make-whole formula and would be determined three business days in advance of the redemption date. We estimate that the redemption price would be approximately 110.3% of the principal amount of the 2014 notes to be redeemed. Based on that estimate, the redemption would result in a pre-tax charge to our net earnings of approximately $37 million, and the total cost would be approximately $331 million (excluding accrued and unpaid interest to the redemption date). Pending the proposed redemption of the 2014 notes, we plan to apply the proceeds to temporarily reduce borrowings under our bank credit facility.

This Current Report on Form 8-K is not intended as a notice of any such redemption. Such notice will be given to holders of the 2014 notes in the manner prescribed in the indenture governing the 2014 notes and at the appropriate time.

(iii) Risk Factors

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

Oil and natural gas prices are volatile. Declines in commodity prices have adversely affected, and in the future may adversely affect, our results of operations, cash flows, financial condition, access to the capital markets, the economic viability of our reserves, and our ability to reinvest in order to maintain or grow our asset base.

Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to a variety of factors that are beyond our control. Approximately 76% of our estimated proved reserves at December 31, 2011 were natural gas, causing us to be particularly dependent on prices for natural gas.

During the fourth quarter of 2011 and continuing into 2012, natural gas prices declined to ten year lows. Further deterioration in prices may mean that it will not be economical to drill or produce natural gas from some of our existing properties, and we may be required to curtail, or stop completely, our production activities in those areas. A continuation of low natural gas prices, or a significant decline in oil prices, may have the following effects on our business:

- impairing our financial condition, liquidity, or ability to fund planned capital expenditures;
- limiting our access to sources of capital, such as equity and debt; or
- prohibiting us from developing our current properties, or from growing our asset base.

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

As of June 30, 2012, we had a principal amount of long-term indebtedness of $1.95 billion, including $348 million drawn under our bank credit facility. As of August 31, 2012, we had a principal amount of long-term indebtedness of $2.02 billion, including $417 million drawn under our bank credit facility. The governing documents of our debt instruments contain covenants and restrictions that require that we meet certain financial tests and place restrictions on the incurrence of additional indebtedness.

Our level of debt 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 flows to service the obligations, which could limit our flexibility in planning for and reacting to changes in our business, and reduce the amount available to reinvest in order to maintain or grow our asset base;

- 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;

- 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;

- place us at a disadvantage compared to companies in our industry that have less debt and other financial obligations; and

- make us more vulnerable to economic downturns, volatile oil, natural gas, and natural gas liquids prices, and adverse developments in our business.

A failure on our part to comply with the financial and other restrictive covenants contained in our bank credit facility and the indentures governing our outstanding senior notes could result in a default under these agreements. Any default under our bank credit facility 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 borrowing base included in our bank credit facility is subject to periodic redetermination by our lenders and is based on the estimated value of our properties using pricing models determined by the lenders at such time. The borrowing base was reaffirmed at $1.25 billion in April 2012, and the next scheduled redetermination of the borrowing base will occur on or about November 1, 2012. Since the process for determining the borrowing base under our bank credit facility involves evaluating the estimated value of our oil and natural gas properties using pricing models determined by the lenders at that time, we believe that it is likely that the recent decline in natural gas and natural gas liquids commodity prices, or a further decline in those prices, will result in a redetermination of our borrowing base and a decrease in the available borrowing amount at the time of the next scheduled redetermination. A decrease in our borrowing base would require us to repay indebtedness in excess of the borrowing base.

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, natural gas, and natural gas liquids prices, financial, business, domestic, and global economic conditions, governmental regulations and environmental regulations, and other factors, many of which we are unable to control. We intend to focus on reducing our debt levels relative to our estimated proved reserves and EBITDA. As market conditions permit, we plan to consider divestitures, offerings of our common or preferred equity securities, and other means to reduce our debt levels and increase our liquidity; however, there is no assurance that we will be able to complete such transactions. If our cash flows are not sufficient to service our debt and other obligations or to meet the financial or other restrictive covenants contained in our bank credit facility and the indentures governing our outstanding senior notes, we may be required to refinance or restructure the debt, sell assets, or sell shares of our common or preferred equity securities all on terms that we do not find attractive, if it can be done at all.

We may not be able to obtain funding under our current bank credit facility because of a decrease in our borrowing base or obtain funding in the capital markets on terms we find acceptable because of a deterioration of the capital and credit markets.

Historically, we have used our cash flows from operations and borrowings under our bank credit facility to fund our capital expenditures and have relied on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions or to refinance debt obligations. We currently have a bank credit facility with lender commitments totaling $1.5 billion and a borrowing base set at $1.25 billion. The borrowing base is determined by the lenders periodically and is based on the estimated value of our properties using pricing models determined by the lenders at such time. The borrowing base was reaffirmed at $1.25 billion in April 2012, and the next scheduled redetermination of the borrowing base will occur on or before November 1, 2012. Also, under the terms of our bank credit facility, our borrowing base will be immediately decreased by an amount equal to 25% of the stated principal amount of senior notes issued in the future (excluding any senior notes that Forest may issue to refinance senior notes outstanding on June 30, 2011). In the future, we may not be able to access adequate funding under our bank credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. Low commodity prices, particularly for natural gas and natural gas liquids, could result in a determination to lower the borrowing base in the future. Since the process for determining the borrowing base under our bank credit facility involves evaluating the estimated value of our oil and natural gas properties using pricing models determined by the lenders at that time, we believe that it is likely that the recent decline in natural gas and natural gas liquids commodity prices, or a further decline in those prices, will result in a redetermination of our borrowing base and a decrease in the available borrowing amount at the time of the next scheduled redetermination. In such case, we would be required to repay any indebtedness in excess of the borrowing base.

In recent years, it has become more difficult to obtain funding in the public and private capital markets because of the volatility of the capital markets. In addition, there is a risk that the cost of obtaining money from the credit markets may increase in the future as lenders and institutional investors may increase interest rates, impose tighter lending standards, refuse to refinance existing debt at maturity on terms similar to existing debt or at all, or reduce or cease to provide any new funding.

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, 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.

Our debt agreements contain restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities.

The indentures governing our senior notes, including the notes to be issued pursuant to the offering of the Notes, and our bank credit facility contain restrictive covenants that will limit our ability and the ability of certain of our subsidiaries to, among other things:

- incur or guarantee additional indebtedness or issue preferred shares;
- pay dividends or make other distributions;
- purchase equity interests or redeem subordinated indebtedness early;
- create or incur certain liens;
- enter into transactions with affiliates; and
- sell assets or merge or consolidate with another company.

Complying with the restrictions contained in some of these covenants will require us to meet certain financial ratios and tests, notably with respect to consolidated interest coverage, total assets, net debt, equity, and net income. For example, our bank credit facility provides that we will not permit our ratio of total debt outstanding to EBITDA (as adjusted for non-cash charges) for a trailing 12-month period to be greater than 4.5 to 1.0 at any time. Our ratio of total debt outstanding to EBITDA for the 12-month period ending June 30, 2012, as calculated in accordance with our bank credit facility, was 3.9. Our need to comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures, or withstand a future downturn in our business.

We are a relatively small company and therefore may not be able to compete effectively.

Compared to many of the companies in our industry, we are a small company. We face difficulties in competing with the larger companies. The costs of doing business in the exploration and production industry, including such costs as those required to explore new oil and natural gas plays, to acquire new acreage, and to develop attractive oil and natural gas projects, are significant. Our limited size can place us at a disadvantage with respect to funding such costs. Our limited size also means that we are more vulnerable to commodity price volatility and overall industry cycles, are less able to absorb the burden of changes in laws and regulations, and that poor results in any single exploration, development, or production play can have a disproportionately negative impact on us. Our size can also impair our ability to attract and retain staff and maintain competitive technical capabilities.

Our estimates of oil and natural gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves and our financial condition.

The proved oil and natural gas reserves information and the related future net revenues information included in our Annual Report on Form 10-K for the year ended December 31, 2011 and in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012 represent only estimates, which are prepared by our internal staff of engineers and the majority of which are audited by DeGolyer and MacNaughton, an independent petroleum engineering firm. Estimating quantities of proved oil and natural gas reserves is a complex, inexact process and depends on a number of interpretations of technical data and various factors and assumptions, including assumptions required by the SEC as to oil, natural gas, and natural gas liquids prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds. As a result, these estimates are inherently imprecise. Any significant inaccuracies or changes in our assumptions or changes in operating conditions could cause the estimated quantities and net present value of the estimated reserves to be significantly different.

At December 31, 2011, approximately 45% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserves 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.

Our estimated proved reserves as of December 31, 2011 were based on a NYMEX HH price of $4.12 per MMBtu for natural gas and a WTI price of $96.08 per barrel for oil, each of which represents the unweighted arithmetic average of the first-day-of-the-month prices during the twelve-month period prior to December 31, 2011, and an average realization for natural gas liquids during that period equal to 46% of the WTI price. For the 12-month period ending on June 30, 2012, the comparable average price for natural gas was $3.15 per MMBtu, the comparable average price for oil was $95.76 per barrel, and the comparable average realization for natural gas liquids was 41% of the WTI price. With respect to natural gas and natural gas liquids, we currently expect the prices for the 12-month period ending on September 30, 2012 to be even lower. We expect that this decline in natural gas and NGL prices, together with the potential conclusion that we will not be able to develop all of our proved undeveloped reserves within the five-year time period required under the SEC s reserve rules, will likely mean that our estimated proved reserves as of December 31, 2012 will be lower than our estimates as of December 31, 2011. For example, during the first six months of 2012, we reclassified approximately 270 Bcfe of our proved undeveloped reserves as of December 31, 2011 from proved to probable status as the reserves were no longer economic and/or would no longer satisfy the five-year limitation using the June 30, 2012 prices referenced above. Although we continue to record new reserves associated with our 2012 drilling program, we do not expect these additions will fully offset the decrease in reserves associated with the decrease in commodity prices discussed above.

You should not assume that any present value of future net cash flows from our estimated proved reserves as set forth in our Annual Report on Form 10-K for the year ended December 31, 2011 represents the market value of our oil and natural gas reserves.

Lower oil, natural gas, and natural gas liquids 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 natural gas activities. Under this method, we capitalize the cost to acquire, explore for, and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and natural 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 natural 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 does not impact cash flows from operating activities, but it does reduce our shareholders equity.

Investments in unproved properties 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 natural gas properties, the amount by which the ceiling limit exceeds the capitalized costs of proved oil and natural 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, natural gas, and natural gas liquids 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 natural gas properties, our unproved properties, or goodwill increases when oil, natural gas, and natural gas liquids 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 or operating costs increase. For example, in the second quarter of 2012, we incurred a $349 million ceiling test write-down, and primarily in connection therewith, we recorded a $290 million valuation allowance on our deferred tax assets. Additional write-downs of the United States cost center may be required in subsequent periods if, among other things, the unweighted arithmetic average of the first-day-of-the-month oil, natural gas, and natural gas liquids prices used in the calculation of the present value of future net revenue from estimated production of estimated proved reserves decline compared to prices used as of June 30, 2012, unproved property values decrease, estimated proved reserve volumes are revised downward, or costs incurred in exploration, development, or acquisition activities exceed the discounted future net cash flows from the additional reserves, if any, attributable to the cost center. We expect that we will incur an additional ceiling test write-down in the third quarter of 2012 that is similar in magnitude to our second quarter write-down. In addition, we expect to recognize a non-cash impairment charge of approximately $65 million in the third quarter of 2012 related to our operations in South Africa.

If we are not able to replace reserves, we will not be able to sustain or grow production.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we replace the reserves we produce through successful development, exploration or acquisition, our proved reserves and production will decline over time.

We do not always find commercially productive reserves through our drilling operations. The seismic data and other technologies that we use when drilling wells do not allow us to determine conclusively prior to drilling a well whether oil or natural gas is present or can be produced economically. Moreover, the costs of drilling, completing, and operating wells are often uncertain. Our drilling activities, therefore, may result in the total loss of our investment or a return on investment significantly below expectation.

Most of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

A sizable portion of our acreage is currently undeveloped. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, cash flow, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control.

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 capacity or access to gathering systems that impact a substantial amount of our production, it could have an adverse impact on our cash flow.

Drilling is a high-risk activity that could result in substantial losses for us.

We conduct a portion of our drilling activities through a wholly-owned drilling subsidiary that operates drilling rigs and 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, among other things, the risk of natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases. 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. We maintain insurance against some, but not all, of the risks described above. Generally, pollution related environmental risks are not fully insurable. We do not insure against business interruption. We cannot assure that our insurance will be fully adequate to cover other losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

Our use of hedging transactions could reduce our cash flow and/or result in reported losses.

We periodically enter into hedging agreements for a portion of our anticipated oil, natural gas, and natural gas liquids production. Our commodity hedging agreements are limited in duration, usually for periods of one year or less; however, we sometimes enter into hedges for longer periods. Should commodity prices increase after we have entered into a hedging transaction, our cash flows will be lower than they would have been without the hedging transaction.

For financial reporting purposes, we do not use hedge accounting, thus we are required to record changes in the fair value of our hedging instruments through our earnings rather than through other comprehensive income had we elected to use hedge accounting. As a consequence, we may report material unrealized losses or gains on our hedging agreements

prior to their expiry. The amount of the actual realized losses or gains will differ and will be based on the actual prices of the commodities on the settlement dates as compared to the hedged prices contained in the hedging agreements. As a result, our periodic financial results will be subject to fluctuations related to our derivative instruments.

Moreover, we may not be able to fully implement our hedging program due to certain regulatory constraints. The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted by Congress is expected to, among other things, impose new requirements and oversight on hedging transactions, including new clearing and margin requirements. While implementing regulations are yet to be finalized by the relevant federal agencies, to the extent that they are applicable to us or our counterparties, we may incur increased costs and cash collateral requirements that could affect our ability to hedge risks associated with our business.

We may incur significant costs related to environmental and other governmental laws and regulations, including those related to hydraulic fracturing, that may materially affect our operations.

Our oil and natural gas operations are subject to various U.S. federal, state, and local laws and regulations, and local and national laws and regulations in Italy and South Africa. Many of the laws and regulations to which our operations are subject include those relating to the protection of the environment. 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, present or future environmental laws and regulations.

We routinely utilize hydraulic fracturing, which is an important and common practice used to stimulate production of hydrocarbons from tight, or low-permeability formations. State oil and gas commissions typically regulate the process. However, several federal entities, including the U.S. Environmental Protection Agency (EPA), have also recently asserted potential regulatory authority over hydraulic fracturing. Some states, such as Texas, have adopted, and some states, including others in which we operate, are considering adopting, regulations that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing operations. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to operate. Restrictions on, or increased costs of, hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Recently proposed or finalized rules and guidance imposing more stringent requirements on the oil and gas exploration and production industry could cause us to incur increased capital expenditures and operating costs as well as decrease our levels of production.

On April 17, 2012, the EPA approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or green completions on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

In addition, federal agencies have recently announced two other regulatory initiatives regarding certain aspects of hydraulic fracturing that could further increase our costs to operate and decrease our levels of production. On May 4, 2012, the U.S. Department of the Interior announced proposed rules that if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon federal and Indian lands and also would strengthen standards for well-bore integrity and the management of fluids that return to the surface during and after fracturing operations on federal and Indian lands. Also on May 4, 2012, the EPA issued draft guidance for federal Safe Drinking Water Act permits issued to oil and natural gas exploration and production operators using diesel during hydraulic fracturing. The adoption or implementation of these regulatory initiatives could cause us to incur increased expenditures and decrease our levels of production.

The credit risk of financial institutions could adversely affect us.

We have entered into transactions with counterparties in the financial services industry, including commercial banks, insurance companies, and their affiliates. These transactions expose us to credit risk in the event of default of our counterparty, principally with respect to hedging agreements but also insurance contracts and bank lending commitments. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. See Note 9 to the consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2011 for a more complete discussion of credit risk with respect to our derivative instruments.

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 platforms. While we recently settled certain litigation relating to the Alaska Assets, litigation relating to decommissioning of the Spurr platform in Cook Inlet remains outstanding.

Item 9.01. Financial Statements and Exhibits.

(d) Exhibits.

Exhibit	**Description**
99.1	Press Release CEO.
99.2	Press Release Guidance.
99.3	Press Release Notes Offering.

SIGNATURES

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

	FOREST OIL CORPORATION (Registrant)	
Dated: September 12, 2012	By	/s/ Cyrus D. Marter IV Cyrus D. Marter IV Senior Vice President, General Counsel and Secretary

INDEX TO EXHIBITS FILED WITH THE CURRENT REPORT ON FORM 8-K

Exhibit	Description	
99.1	Press Release	CEO.
99.2	Press Release	Guidance.
99.3	Press Release	Notes Offering.