MARATHON OIL CORP
Form 10-K
February 29, 2012
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2011

Commission file number 1-5153

Marathon Oil Corporation

(Exact name of registrant as specified in its charter)

Delaware	**25-0996816**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5555 San Felipe Street, Houston, TX 77056-2723

(Address of principal executive offices)

(713) 629-6600

(Registrant s telephone number, including area code)

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 $1.00	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ 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 þ

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 and (2) has been subject to such filing requirements for the past 90 days. Yes þ 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 þ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. þ

Indicate by check mark whether the registrant is a large accelerated filer, accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ 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 þ

The aggregate market value of Common Stock held by non-affiliates as of June 30, 2011: $22,773 million. This amount is based on the closing price of the registrant s Common Stock on the New York Stock Exchange on that date. Shares of Common Stock held by executive officers and directors of the registrant are not included in the computation. The registrant, solely for the purpose of this required presentation, has deemed its directors and executive officers to be affiliates.

There were 703,925,642 shares of Marathon Oil Corporation Common Stock outstanding as of January 31, 2012.

Documents Incorporated By Reference:

Portions of the registrant s proxy statement relating to its 2012 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

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MARATHON OIL CORPORATION

Unless the context otherwise indicates, references to Marathon Oil, we, our, or us in this Annual Report on Form 10-K are references Marathon Oil Corporation, including its wholly-owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest).

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DEFINITIONS

Throughout the following report, the following company or industry specific terms and abbreviations are used.

AMPCO Atlantic Methanol Production Company LLC, a company in which we own a 45 percent equity interest.

AOSP Athabasca Oil Sands Project, an oil sands mining, transportation and upgrading joint venture located in Alberta, Canada, in which we hold a 20 percent interest.

bbl One stock tank barrel, which is 42 U.S. gallons liquid volume.

bbld barrels per day.

bboe Billion barrels of oil equivalent. Natural gas is converted to a boe based on the energy equivalent, which on a dry gas basis is six mcf of gas per one barrel of oil equivalent.

bcf Billion cubic feet.

boe Barrels of oil equivalent.

boed Barrels of oil equivalent per day.

BOEMRE United States Bureau of Ocean Energy Management, Regulation and Enforcement.

btu British thermal unit, an energy equivalency measure.

DD&A Depreciation, depletion and amortization.

Developed acreage The number of acres which are allocated or assignable to producing wells or wells capable of production.

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

Downstream business The refining, marketing and transportation (RM&T) operations, spun-off June 30, 2011 and now treated as discontinued operations.

Dry well A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion.

EG Equatorial Guinea.

EGHoldings Equatorial Guinea LNG Holdings Limited, an LNG production company located in Equatorial Guinea in which we own a 60 percent equity interest.

E&P Our Exploration and Production segment which explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.

EPA Environmental Protection Agency.

Exit rate The average daily rate of production from a well or group of wells in the last month of the period stated.

Exploratory well A well drilled to find oil or gas in an unproved area, find a new reservoir in a field previously found to be productive in another reservoir, or extend a known reservoir.

FASB Financial Accounting Standards Board.

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

FPSO Floating production, storage and offloading vessel.

IASB International Accounting Standards Board.

IFRS International Financial Reporting Standards.

IG Our Integrated Gas segment which produces and markets products manufactured from natural gas, such as LNG and methanol, in EG.

IP Average daily rate of production from a well in the initial 30 days of its operation, which may not be indicative of the rate of future production.

IRS U.S. Internal Revenue Service.

KRG Kurdistan Regional Government.

LNG Liquefied natural gas.

LPG Liquefied petroleum gas.

Marathon The consolidated company prior to the June 30, 2011 spin-off of the downstream business.

Marathon Oil The Company as it exists following the June 30, 2011 spin-off of the downstream business.

Marathon Petroleum Corporation (MPC) The separate independent company which now owns and operates the downstream business.

mbbl Thousand barrels.

mbbld Thousand barrels per day.

mboe Thousand barrels of oil equivalent.

mboed Thousand barrels oil equivalent per day.

mcf Thousand cubic feet.

mmbbl Million barrels.

mmboe Million barrels of oil equivalent.

mmbtu Million British thermal units.

mmcfd Million cubic feet per day.

mmt Million metric tonnes.

mtd Thousand metric tonnes per day.

Net acres or Net wells The sum of the fractional working interests owned by us in gross acres or gross wells.

OPEC Organization of Petroleum Exporting Countries.

OSM Our Oil Sands Mining segment which mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

Productive well A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

Proved reserves Proved oil, natural gas and synthetic crude oil reserves are those quantities of oil, natural gas and synthetic crude oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible.

Proved developed reserves Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved undeveloped reserves 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.

PSC Production sharing contract.

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Quest CCS Quest Carbon Capture and Storage project at the AOSP in Alberta, Canada.

Reserve replacement ratio A ratio which measures the amount of proved reserves added to our reserve base during the year relative to the amount of oil and gas produced.

Royalty interest An interest in an oil or natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

SAGE U.K. Scottish Area Gas Evacuation system composed of a pipeline and processing terminal.

SEC U.S. Securities and Exchange Commission.

Seismic An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures).

U.K. United Kingdom.

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 and natural gas regardless of whether such acreage contains proved reserves.

U.S. United States of America.

U.S. GAAP Accounting principles generally accepted in the U.S.

Working interest (WI) The interest in a mineral property which gives the owner that share of production from the property. A working interest owner bears that share of the costs of exploration, development and production in return for a share of production. Working interests are typically burdened by overriding royalty interest or other interests.

WTI West Texas Intermediate crude oil, an index price.

Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. Business, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, and Item 7A. Quantitative and Qualitative Disclosures about Market Risk, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. These statements typically contain words such as anticipate, believe, estimate, expect, forec plan, predict, target, project, could, may, should, would or similar words, indicating that future outcomes are uncertain. In accorda harbor provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements in this Report may include, but are not limited to, levels of revenues, income from operations, net income or earnings per share; levels of capital, exploration, environmental or maintenance expenditures; the success or timing of completion of ongoing or anticipated capital, exploration or maintenance projects; volumes of production or sales of liquid hydrocarbons, natural gas, and synthetic crude oil; levels of worldwide prices of liquid hydrocarbons and natural gas; levels of liquid hydrocarbon, natural gas and synthetic crude oil reserves; the acquisition or divestiture of assets; the effect of restructuring or reorganization of business components; the potential effect of judicial proceedings on our business and financial condition; levels of common share repurchases; and the anticipated effects of actions of third parties such as competitors, or federal, foreign, state or local regulatory authorities.

PART I

Item 1. Business

General

Marathon Oil Corporation was incorporated in 2001 and is an international energy company engaged in exploration and production, oil sands mining and integrated gas with operations in the United States, Angola, Canada, Equatorial Guinea, Indonesia, the Iraqi Kurdistan Region, Libya, Norway, Poland and the United Kingdom. We are based in Houston, Texas with our corporate headquarters at 5555 San Felipe Road, Houston, Texas 77056-2723 and a telephone number of (713) 629-6600.

On June 30, 2011, the spin-off of Marathon s downstream business was completed, creating two independent energy companies: Marathon Oil and MPC. Marathon shareholders at the close of business on the record date of June 27, 2011 received one share of MPC common stock for every two shares of Marathon common stock held. Fractional shares of MPC common stock were not distributed and any fractional share of MPC common stock otherwise issuable to a Marathon shareholder was sold in the open market on such shareholder s behalf, and such shareholder received a cash payment with respect to that fractional share. A private letter ruling received in June 2011 from the IRS affirmed the tax-free nature of the spin-off. Activities related to the downstream business have been treated as discontinued operations in all periods presented in this Annual Report on Form 10-K, with additional information in Item 8. Financial Statements and Supplementary Data Note 3 to the consolidated financial statements.

Strategy and Results Summary

Assets within our three segments are at various stages in their lifecycle: base, growth or exploration. We have a stable group of base assets, which include our OSM and IG segments and E&P assets in Norway, Equatorial Guinea, Libya, the U.K. and the U.S. These assets generate much of the cash that will be available for investment in our growth assets and exploration projects. Growth assets are where we expect to make significant investment in order to realize oil and gas production and reserve increases. We are focused on U.S. liquid hydrocarbon growth by developing liquids-rich shale play positions, including most recently the establishment of a strong position in the core of the Eagle Ford shale play. In addition to the U.S. shale plays, growth assets include the development of Angola Block 31, our discoveries in the Iraqi Kurdistan Region, select Gulf of Mexico blocks and our Canadian in-situ assets. Our areas of exploration are Poland, the Iraqi Kurdistan Region, Norway and the Gulf of Mexico. We continually evaluate ways to optimize our portfolio through acquisitions and divestitures, with a previously stated goal of divesting between $1.5 and $3.0 billion of non-core assets between 2011 and 2013. Through January 2012, we closed such transaction having values of $640 million.

We ended 2011 with proved reserves of 1.8 bboe, an 10 percent increase over 2010. Average sales volumes were 219 mbbld of liquid hydrocarbon, 866 mmcfd of natural gas and 43 mbbld of synthetic crude oil, with 66 percent of our liquid hydrocarbon sales volumes from international operations, for which average realizations have exceeded WTI prices. We invested in the development of assets in all our segments, totaling $3.4 billion in capital expenditures related to continuing operations for the year, with $3 billion related to our E&P segment. We expect continued capital expenditures, primarily funded with cash flow from operations, in exploration and development activities in order to realize continued reserve and sales growth. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations-Outlook, for discussion of our $4.8 billion capital spending budget for 2012.

The above discussion of strategy and results includes forward-looking statements with respect to the goal of divesting between $1.5 and $3.0 billion of non-core assets between 2011 and 2013 and expected investment in exploration and development activities. Some factors that could potentially affect the divestiture of non-core assets and expected investment in exploration and development activities include changes in prices of and demand for liquid hydrocarbons and natural gas, actions of competitors, occurrence of acquisitions or dispositions of oil and natural gas properties, future financial condition and operating results, and economic, and/or regulatory factors affecting our businesses, the identification of buyers and the negotiation of acceptable prices and other terms, as well as other customary closing conditions. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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The map below illustrates the locations of our worldwide operations.

Segment and Geographic Information

For operating segment and geographic financial information, see Item 8. Financial Statements and Supplementary Data Note 8 to the consolidated financial statements.

Exploration and Production Segment

In the discussion that follows regarding our exploration and production operations, references to net wells, sales or investment indicate our ownership interest or share, as the context requires.

We are engaged in oil and gas exploration, development and/or production activities in the United States, Angola, Canada, Equatorial Guinea, Indonesia, the Iraqi Kurdistan Region, Libya, Norway, Poland, and the United Kingdom.

Liquids-Rich Shale Plays

Eagle Ford In the fourth quarter of 2011, we closed several acquisitions in the Eagle Ford shale play of south Texas for a total cash consideration of $4.5 billion. See Item 8. Financial Statements and Supplementary Data Note 5 to the consolidated financial statements for additional information about these acquisitions.

Upon finalization of the 2011 Eagle Ford acquisition transactions, we will have just over 300,000 net acres in the Eagle Ford shale with an average working interest of approximately 80 percent. As of December 31, 2011, we had 14 operated drilling rigs active in the play, with plans to increase to 18 drilling rigs and 4 dedicated hydraulic fracturing crews by the end of 2012. Our plans include drilling and completing 200 230 gross (160 185 net) operated wells in 2012.

Including the impact of our fourth quarter 2011 acquisitions, annual net sales for 2011 were 2 mboed, with a December exit rate of 13 mboed. Our production from the Eagle Ford shale is either sold at the lease or moved via truck or pipeline to markets. We own and operate the Sugarloaf gathering system, a 42-mile natural gas pipeline through the heart of our recently purchased acreage in Karnes, Atascosa, and Bee Counties of south Texas. Our future production estimates will require additional markets, transportation, storage and plant processing to be either contracted or constructed and a variety of negotiations are underway with a goal of continued access to adequate infrastructure and markets. Key considerations in this development will be the timing of contract availability and efforts to receive optimal price based upon delivery location.

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Bakken We hold just over 400,000 net acres in the Bakken shale oil play in the Williston Basin of North Dakota and eastern Montana with an average working interest in the acreage of approximately 80 percent. Throughout 2011, we continued selective acreage acquisitions and leasing, adding approximately 40,000 net acres which expanded to a new prospect area. In 2011 we drilled 61 gross (55 net) operated wells and completed 71 gross (63 net) operated wells. We also moved from 20-stage to 30-stage hydraulic fracturing, which increases both production rates and estimated ultimate recovery from the wells. At December 31, 2011, we had 7 operated drilling rigs and 2 dedicated hydraulic fracturing crews in our Bakken shale program, and expect to add one more rig in 2012 to accomplish plans to drill 69 gross (53 net) and complete 72 84 gross (53 61 net) operated wells in 2012.

Our net sales from the Bakken shale averaged 17 mboed in 2011, a 36 percent increase over 2010, and our production exit rate for 2011 was 24 mboed. We sell our Bakken production into local markets predominately via trucking. A variety of negotiations are underway to provide adequate infrastructure and markets for our future estimated production levels, including the potential export of volumes from the regional markets via pipeline or rail projects.

Anadarko Woodford In the Anadarko Woodford shale play in Oklahoma, we hold 160,000 net acres of which approximately 100,000 acres are held by production. In 2011, we executed an operated drilling program focused on the liquids-rich areas of the play, drilling 15 gross (11 net) exploration and 8 gross (6 net) development wells, of which 11 gross (9 net) wells were completed.

The Shi Randall well, in which we hold a 50 percent working interest, was completed in the third quarter of 2011. The Shi Randall had a gross IP of 455 bbld of liquid hydrocarbons and 6 mmcfd of natural gas, subject to pipeline constraints. It was one of the initial wells in the Knox area (southern Woodford) and is helping to prove up a prospective area where we have a strong acreage position.

The Anadarko Woodford shale averaged net sales of 2 mboed during 2011. In 2012, we plan to maintain our current level of 6 rigs and drill 35 40 gross (19 22 net) operated wells with more focus on development drilling. Outside-operated projects could add an additional 30 50 gross (6 10 net) wells. See below for additional discussion of our conventional, primarily natural gas production operations in Oklahoma.

DJ Basin In 2010, we began leasing in the Niobrara play in the DJ Basin of northern Colorado and southeast Wyoming and built an acreage position of approximately 180,000 acres. In April 2011, we farmed-out a 30 percent undivided working interest retaining 70 percent and operatorship. See Item 8. Financial Statements and Supplementary Data Note 6 to the consolidated financial statements for additional information regarding this transaction. As of December 31, 2011 we hold 151,000 net acres. In 2011, we drilled a total of 12 gross (7 net) operated wells, with four gross (two net) operated wells completed. We are currently operating 2 drilling rigs in the DJ Basin and expect to drill 25 35 gross (13 19 net) operated wells in 2012. Outside-operated projects could add an additional 25 35 gross (4 5 net) wells. We exited December with a net production rate of 86 boed. We have other natural gas assets in Colorado which are discussed below.

United States

Alaska We produce natural gas in the Cook Inlet and adjacent Kenai Peninsula of Alaska where we have operated and outside-operated interests in 10 fields covering 118,000 net acres. In 2011, we drilled 1 operated well in the Ninilchik field and participated in 1 non-operated horizontal well in the McArthur River field, both in the Cook Inlet. Plans for 2012 include continued investments in production optimization and operational reliability.

Net natural gas sales from Alaska averaged 94 mmcfd in 2011. Typically, our natural gas sales from Alaska are seasonal in nature, trending down during the second and third quarters of each year and increasing during the fourth and first quarters. To manage supplies to meet contractual demand we produce and store natural gas in a partially depleted reservoir in the Kenai natural gas field.

Complementing our production operations in Alaska is our majority ownership in four operated natural gas pipelines totaling 140 miles. These are bidirectional systems providing transportation from multiple producers to numerous end users in and around the Cook Inlet.

Colorado We hold leases of 8,700 net acres with natural gas production in the Piceance Basin of Colorado, located in the Greater Grand Valley field complex, with net sales of 20 mmcfd in 2011. Currently the field has 77 gross/net wells producing.

Oklahoma We have long-established operated and non-operated conventional production operations in several Oklahoma fields from which 2011 sales averaged 2 mbbld of liquid hydrocarbons and 53 mmcfd of natural gas. In 2011 we participated in 7 gross (2 net), non-operated wells in the state. We also drilled 1 company operated well. Plans for 2012 include 11 gross (2 net) wells, targeting liquids.

Texas/North Louisiana/New Mexico In east Texas and north Louisiana, we hold 184,000 net acres. Approximately 20,000 of the acres are in the Haynesville and Bossier natural gas shale plays. Most of the acreage in these shale plays is held by production. We participated in 3 gross (1 net) non-operated wells in the area during 2011. Conventional production was primarily from the Mimms Creek, Pearwood and Oletha fields, in 2011. Net sales from east Texas and north Louisiana averaged 7 mboed.

We also participate in several outside-operated Permian Basin fields in west Texas and New Mexico. Net sales from this area were 7 mboed in 2011. Activity in 2012 will center around carbon dioxide flood programs in the Seminole and Vacuum fields.

Wyoming We hold 260,000 net acres in Wyoming and have almost 100 years of exploration and development in the state. We have ongoing enhanced oil recovery projects at the mature Bighorn Basin and Wind River Basin fields and initiated an additional enhanced recovery project at our 100 percent owned and operated Pitchfork field in 2011. We have conventional natural gas operations in the Greater Green River Basin and unconventional coal bed natural gas operations in the Powder River Basin. In 2011, we drilled 17 gross (17 net) operated development wells in Wyoming, which included five wellbore re-entries and plan 3 4 gross (3 4 net) operated wells in 2012. Our Wyoming sales averaged 17 mbbld of liquid hydrocarbons and 75 mmcfd of natural gas during 2011. In addition, we own and operate the 420-mile Red Butte Pipeline. This crude oil pipeline connects Silvertip Station on the Montana/Wyoming state line to Casper, Wyoming.

West Virginia/Pennsylvania In the Appalachian Basin we hold 82,000 net acres in the Marcellus shale natural gas play in Pennsylvania and West Virginia. In February 2011, we entered into a joint venture on a large portion of our Marcellus shale acreage position. Under the agreement which ends in 2012, our joint venture partner will earn 50 percent of approximately 60,000 acres under a drilling carry and has an option to acquire our remaining acreage while we retain the rights to continue to market the acreage to others. In 2011, 2 gross (1 net) outside-operated wells were drilled with 1 gross (0.5 net) well awaiting completion. We expect to participate in 4 gross (2 net) wells in 2012.

Gulf of Mexico Production

On December 31, 2011, we held material interests in seven producing fields, four of which are company-operated.

We operate and have a 65 percent working interest in the Ewing Bank Block 873 platform which is located 130 miles south of New Orleans, Louisiana. The platform started operations in 1994 and serves as a production hub for the Lobster, Oyster and Arnold fields on Ewing Bank blocks 873, 917 and 963. The facility also processes third-party production via subsea tie-backs.

We own a 50 percent working interest in the outside-operated Petronius field on Viosca Knoll Blocks 786 and 830 located 130 miles southeast of New Orleans, which includes six producing wells. The Petronius platform is capable of providing processing and transportation services to nearby third-party fields. During 2012, we plan to acquire seismic data in order to identify future drilling opportunities.

We hold a 30 percent working interest in the outside-operated Neptune field located on Atwater Valley Block 575, 120 miles off the coast of Louisiana. The development includes seven subsea wells tied back to a stand-alone platform. Additional drilling and recompletion activity is being considered for 2012.

We have a 100 percent operated working interest and an 81 percent net revenue interest in the Droshky development located on Green Canyon Block 244 off the coast of Louisiana. This development began production in mid-July of 2010 and reached peak net production of 45 mboed in the third quarter of 2010. The field will be produced to abandonment pressures which are expected to be reached in the first half of 2012.

We hold a 68 percent working interest in Ozona. Development of our operated Ozona prospect, located on Garden Banks Block 515, was delayed by the Drilling Moratorium (discussed below) and subsequent regulatory changes. In 2011, we completed the Ozona well as a single zone producer tied back to a non-operated host platform. First production began in late December 2011.

Average net sales for 2011 from the Gulf of Mexico were 30 mbbld of liquid hydrocarbons and 24 mmcfd of natural gas.

We also own a 34 percent outside-operated interest in the Neptune gas plant located onshore Louisiana. This high efficiency gas plant, which services four high pressure offshore and onshore pipelines, has a 650 mmcfd capacity.

Gulf of Mexico Exploration

We have 21 prospects, 16 of which are operated in the Gulf of Mexico. As a result of an explosion and significant spill from a deepwater rig in the Gulf of Mexico, the U.S. Department of the Interior issued a drilling moratorium on May 30, 2010 (Drilling Moratorium), to suspend the drilling of deepwater wells, and prohibit drilling any new deepwater wells (defined as greater than 500 foot water depth). The Drilling Moratorium was lifted on October 12, 2010. Our first exploration plan approval was received in August 2011. In 2011, we received lease extensions for 26 blocks in the Gulf of Mexico which had been impacted by the Drilling Moratorium.

A successful deepwater oil discovery well was drilled on the Gunflint prospect located on Mississippi Canyon Block 948, 160 miles southeast of New Orleans in 2008. We own a 15.25 percent interest in this outside-operated prospect. Gunflint prospect appraisal wells were subject to the Drilling Moratorium. Drilling of the first appraisal well began in December 2011, and a second appraisal well is planned for mid-year 2012.

In the first quarter of 2009, we participated in a deepwater oil discovery on the Shenandoah prospect located on Walker Ridge Block 52. We own a 10 percent interest in this outside-operated prospect. The first appraisal well is planned for mid-year 2012.

In March 2011, we completed our evaluation of the Flying Dutchman exploratory well, located on Green Canyon Block 511. We determined that the options to develop were not viable and all well costs have been expensed.

In accordance with the federal government s Drilling Moratorium, we temporarily suspended drilling an exploratory well on the Innsbruck prospect located on Mississippi Canyon Block 993 at a depth of 19,800 feet as compared to a proposed total depth of 29,500 feet. In 2011, we received approval for our current exploration plan from the BOEMRE. We have contracted a rig for this project and drilling is expected to commence in the third quarter of 2012. In December 2011, we assigned a 40 percent interest in the portion of Mississippi Canyon Block 993 that includes Innsbruck, in exchange for a 30 percent non-operated interest in Green Canyon Blocks 403 and 404 in the Kilchurn prospect plus reimbursement of certain well costs incurred to date on Innsbruck. We now have a 45 percent working interest in Innsbruck and continue to operate the prospect. The operator commenced drilling on the Kilchurn prospect in December 2011.

In October 2011, we received approval of an exploration plan from the BOEMRE for the Key Largo prospect located on Walker Ridge Block 578. We have a 60 percent working interest and are the operator of this prospect. Drilling is expected in the second half of 2012.

Africa

Equatorial Guinea We own a 63 percent operated working interest under a PSC in the Alba field which is offshore EG. During 2011, EG net liquid hydrocarbon sales averaged 38 mbbld, and net natural gas sales were 443 mmcfd. Planned maintenance in EG is scheduled for a 28-day period from late first quarter through early second quarter 2012, with operations expected to be completely shut down for eight of those days.

We hold a 63 percent operated working interest in the Deep Luba discovery on the Alba Block and we are the operator with a 90 percent interest in the Corona well on Block D. These wells are part of our long-term LNG strategy. We expect these discoveries to be developed when the natural gas supply from the nearby Alba field starts to decline.

We also own a 52 percent interest in Alba Plant LLC, an equity method investee that operates an onshore LPG processing plant located on Bioko Island. Alba field natural gas is processed by the LPG plant. Under a long-term contract at a fixed price per btu, the LPG plant extracts secondary condensate and LPG from the natural gas stream and uses the natural gas in its operations. During 2011, a gross 890 mmcfd of natural gas was supplied to the LPG production facility and 4 mbbld of secondary condensate and 11 mbbld of LPG were produced by Alba Plant LLC. Our share of the income ultimately generated by the subsequent export of secondary condensate and LPG produced by Alba Plant LLC is reflected in our E&P segment.

As part of our Integrated Gas segment, we own 45 percent of AMPCO and 60 percent of EGHoldings, both of which are accounted for as equity method investments. AMPCO operates a methanol plant and EGHoldings operates an LNG production facility, both located on Bioko Island. Dry natural gas from the Alba field, which remains after the condensate and LPG are removed by Alba Plant LLC, is supplied to both of these facilities under long-term contracts at fixed prices. Because of the location of and limited local demand for natural gas in Equatorial Guinea, we consider the prices under the contracts with Alba Plant LLC, AMPCO and EGHoldings to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances. Our share of the income ultimately generated by the subsequent export of methanol produced by AMPCO and LNG produced by EGHoldings is reflected in our Integrated Gas segment as discussed below. During 2011, a gross 127 mmcfd of dry natural gas was supplied to the methanol plant and a gross 668 mmcfd of dry gas was supplied to the LNG production facility. Any remaining dry gas is returned offshore and reinjected into the Alba field for later production.

Libya Civil unrest, which began in February 2011 in parts of North Africa, escalated to armed conflict in Libya where we hold a 16 percent working interest in the Waha concessions, which encompass almost 13 million acres located in the Sirte Basin of eastern Libya. During the first quarter 2011, all production operations in Libya were suspended. In the

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fourth quarter of 2011, limited production resumed from the Waha concessions, but we made no deliveries of hydrocarbons. In January 2012, Libya produced 190 gross mbbld (25 net mbbld), and sales are planned to resume in the first quarter of 2012. The return of our operations in Libya to pre-conflict levels is unknown at this time; however, we and our partners in the Waha concessions are assessing the condition of our assets and determining when the full resumption of operations will be viable.

Angola Offshore Angola, we hold 10 percent working interests in Blocks 31 and 32, both of which are outside-operated. The discoveries on Blocks 31 and 32 represent several potential development hubs. In 2008, we received approval to proceed with the first deepwater development project, called the PSVM development, which includes the Plutao, Saturno, Venus and Marte discoveries and one successful appraisal well in the northeastern portion of Block 31. The PSVM development will utilize an FPSO with a total of 48 production and injection wells. Development drilling began in 2010 and first production is anticipated in mid-2012. The potential for a second development hub on this block is being evaluated. Studies are underway to establish a development in the eastern part of Block 32 and to assess the development potential of the other discoveries. We anticipate at least one development on Block 32.

Europe

Norway We operate 10 licenses and hold interests in over 249,000 net acres on the offshore Norwegian continental shelf. In 2011, net sales from Norway averaged 80 mbbld of liquid hydrocarbons and 42 mmcfd of gas.

The Alvheim development is comprised of the Kameleon, East Kameleon and Kneler fields, in which we have a 65 percent working interest, and the Boa field, in which we have a 58 percent working interest. It is produced to the Alvheim complex which consists of an FPSO with subsea infrastructure. In 2011, due to debottlenecking efforts, capacity of the FPSO increased to 86 mbbld net (149 mbbld gross). Produced oil is transported by shuttle tanker and produced natural gas is transported to the SAGE system by pipeline. At the end of 2011, the Alvheim development included 13 producing wells and two water disposal wells. An additional development well is planned in 2012.

The nearby outside-operated Vilje field, in which we own a 47 percent working interest, began producing through the Alvheim complex in August 2008. At the end of 2011, two wells were producing and an additional development, Vilje Sor had been approved. Production from Vilje Sor is estimated to begin near the end of 2013.

The Volund field, five miles south of the Alvheim FPSO was the second subsea development tied back to the Alvheim complex. The Volund development, in which we own a 65 percent operated working interest, consists of three production wells and one water injection well. First production from Volund was announced in September 2009. It initially functioned as a swing producer to allow us to maintain full capacity on the Alvheim FPSO until the second quarter of 2010 when we commenced full production. Drilling of an additional development well at Volund is planned for fourth quarter 2012, with first production scheduled in early 2013.

Also offshore Norway, are the Boyla (formerly Marihone) and Viper discoveries in which we hold a 65 percent operated working interest. The Boyla oil discovery is located in license PL340 about 12 miles south of the Volund and Alvheim fields. The Viper oil discovery is located in license PL203, immediately next to the Volund field in license PL150. Both discoveries are being evaluated for possible tie back to the Alvheim complex. An investment decision on Boyla could occur in the second quarter of 2012, with first production estimated to begin in the fourth quarter of 2014.

Exploration activities will continue in 2012 and 2013. The Velsemøy well is expected to begin drilling late in 2012 in license PL531 where we hold a 10 percent carried working interest. Drilling is expected to commence in the first quarter of 2013 on the Sverdrup well in license PL 330 where we hold a 30 percent operated working interest.

United Kingdom Net sales from the U.K. averaged 21 mbbld of liquid hydrocarbons and 55 mmcfd of natural gas. Our largest asset in the U.K. sector of the North Sea is the Brae area complex where we are the operator and have a 42 percent working interest in the South, Central, North and West Brae fields and a 39 percent working interest in the East Brae field. The Brae Alpha platform and facilities host the South, Central and West Brae fields. The North Brae field, which is produced via the Brae Bravo platform, and the East Brae field, which is produced via the East Brae platform, are natural gas condensate fields. The East Brae platform also hosts the nearby Braemar field in which we have a 28 percent working interest. Two development wells were completed at West Brae in early 2011 and we continue to pursue Brae complex projects designed to maximize natural gas recovery and maintain deliverability rates to the U.K. market.

The strategic location of the Brae platforms, along with pipeline and onshore infrastructure, has generated third-party processing and transportation business since 1986. Currently, the operators of twenty-five third-party fields are contracted to use the Brae system and 73 mboed are being processed or transported through the Brae infrastructure. In 2011, we installed a new module to accommodate the tie back of the third-party operated Devenick field. In addition to generating processing and pipeline tariff revenue, this third-party business optimizes infrastructure usage.

The Brae group owns a 50 percent interest in the outside-operated SAGE system. The SAGE pipeline transports natural gas from the Brae area, and the third-party Beryl area, and has a total wet natural gas capacity of 1.1 bcf per day. The SAGE terminal at St. Fergus in northeast Scotland processes natural gas from the SAGE pipeline as well as approximately 1 bcf per day of third-party natural gas.

In the U.K. Atlantic Margin west of the Shetland Islands, we own an average 30 percent working interest in the outside-operated Foinaven area complex, consisting of a 28 percent working interest in the main Foinaven field, 47 percent working interest in East Foinaven and 20 percent working interest in the T35 and T25 fields. The export of Foinaven liquid hydrocarbons is via shuttle tanker from the FPSO to market. All natural gas sales are to the non-operated Magnus platform for use as injection gas. An upgrade of equipment on the FPSO is expected to extend the life of the fields through 2021. Additionally, the planned installation of replacement flowlines should secure the long-term integrity of the subsea infrastructure, but the related downtime is expected to cause a reduction in sales volumes in 2012. Average net sales from Foinaven were 12 mboed in 2011.

Poland Between December 2009 and October 2010, we acquired eleven 5-year licenses, totaling 2.3 million gross acres. In 2011, we farmed-out to two companies an aggregate 49 percent undivided interest in ten of these licenses which will be earned through drilling. As of December 31, 2011, we hold a 51 percent working interest in these 10 concessions, a 100 percent interest in the remaining concession for a total of 1.2 million net acres. We are operator under all licenses. We are in the early stages of exploring and evaluating the full potential of these holdings. We drilled, cored and logged our first vertical exploratory well in late 2011 and are evaluating the data. In addition, we expect to complete proprietary 2-D seismic acquisitions in the first quarter of 2012. We have a drilling commitment of one well per license and plan to drill 6 7 gross (3 4 net) exploration wells in 2012.

Canada

We hold interests in both operated and outside-operated exploration stage oil sand leases in Alberta, Canada, which would be developed using in-situ methods of extraction. These leases cover approximately 143,000 gross acres (52,000 net) in four project areas: Namur, in which we hold a 60 percent operated interest; Birchwood, in which we hold a 100 percent operated interest; Ells River, in which we hold a 20 percent outside-operated interest and Saleski in which we hold a 33 percent outside-operated interest. Exploration on the Birchwood prospect continued in the winter of 2011-2012 with a seismic program and water well drilling. Approximately 100 stratigraphic test wells were drilled on the Birchwood prospect in the winter of 2010-2011 providing data for the ongoing assessment of reservoir quality. We expect sanction of a pilot project in 2013.

Other International

Iraqi Kurdistan Region In October 2010, we acquired a position in four exploration blocks in the Iraqi Kurdistan Region. In aggregate, these contracts provide us with access to approximately 368,000 net acres. We signed PSCs for operatorship and 80 percent ownership in the Harir and Safen blocks northeast of Erbil. The KRG holds a 20 percent carried interest in these blocks. We have committed to a seismic program and to drilling one well on both Hafir and Safen during the initial three-year exploration period. We were assigned interests in two additional outside-operated blocks located north-northwest of Erbil: Atrush, in which we have a 16 percent ownership (the KRG holds a 4 percent carried interest), and Sarsang, in which we have a 20 percent interest (the KRG holds a 5 percent carried interest). In 2011, we announced the Atrush-1 discovery on the Atrush block and a second discovery, the Swara Tika-1 well on the Sarsang block. The Swara Tika-2, an appraisal well on the Sarsang block, commenced drilling in the fourth quarter of 2011. The Atrush-2, an appraisal well on the Atrush block, is planned for 2012. Planning is underway on extended well testing and early production systems, with first production expected in the fourth quarter of 2012.

Indonesia We are the operator of three exploration licenses in Indonesia: the Pasangkayu block with a 70 percent interest, the Kumawa block with a 55 percent interest, and the Bone Bay block with a 55 percent interest. In 2011 and 2010, wells were drilled on the Bravo and Romeo prospects in the Pasangkayu block. These wells were expensed as dry holes. We have notified our joint venture partner and the Indonesian government that we intend to relinquish the PSC on the Pasangkayu block. Discussions continue and we are awaiting a government response. We are evaluating the Bone Bay and Kumawa blocks.

Acquisitions and Dispositions

As previously discussed, during 2011 we closed several acquisition transactions in the Eagle Ford shale play and farmed-out minority interests in our DJ Basin and Poland acreage. Also, in March 2011, we closed the sale of our outside-operated interests in the Gudrun field development and the Brynhild and Eirin exploration areas offshore Norway.

In October 2011, we entered into definitive agreements to sell our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline L.L.C. and certain other oil pipeline interests including the Eugene Island Pipeline System. The transaction closed on

January 3, 2012.

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In December 2011 we sold our 25 percent interest in the Stones prospect located on Walker Ridge Block 508 to the operator. We also exchanged a 100 percent interest in Atwater Valley Block 398 in the Sandpiper prospect, for a 100 percent interest in Walker Ridge Block 577 in the Key Largo prospect and a 20 percent interest in Green Canyon Block 286 in the Hypnos prospect. After this transaction, we hold a 50 percent interest in Green Canyon Block 286 and a 100 percent interest in Walker Ridge Block 577.

See Item 8. Financial Statements and Supplementary Data Note 5 to the consolidated financial statements for additional information about the acquisitions and Note 6 for additional information about the farm-outs and divestitures.

The above discussion of the E&P segment includes forward-looking statements with respect to anticipated future exploratory and development drilling activity, drilling rig activity in the U.S., planned maintenance downtime, timing of reaching abandonment pressures in Droshky, continued investments in Alaska, timing of first production from Vilje Sor, Boyla and Kurdistan, planned acquisition of seismic data for Petronius, plans to achieve first production from the PSVM development on Block 31 offshore Angola and other possible developments, plans to resume sales in Libya and the expected extension of the Foinaven fields. Some factors which could possibly affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, drilling rig availability, unforeseen hazards such as weather conditions, natural disasters, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. The foregoing forward-looking statements may be further affected by the inability to obtain or delay in obtaining necessary government and third-party approvals and permits. The offshore developments could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. Predicted planned maintenance and FPSO downtime are good faith estimates and preliminary, and therefore, subject to change. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Productive and Drilling Wells

For our E&P segment, the following tables set forth gross and net productive wells and service wells as of December 31, 2011, 2010 and 2009 and drilling wells as of December 31, 2011.

	Productive Wells[a]							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2011								
United States	5,809	2,058	3,121	1,876	2,313	734	55	28
Equatorial Guinea	-	-	14	9	4	3	-	-
Other Africa[b]	-	-	-	-	1	-	-	-
Total Africa	-	-	14	9	5	3	-	-
Total Europe	73	31	40	16	28	10	2	1
Total Other International	-	-	-	-	-	-	1	-
Worldwide	5,882	2,089	3,175	1,901	2,346	747	58	29
2010								
United States	4,818	1,860	3,145	1,905	2,466	746		
Equatorial Guinea	-	-	13	9	5	3		
Other Africa	1,022	168	3	-	94	16		
Total Africa	1,022	168	16	9	99	19		
Total Europe	71	30	40	16	29	11		
Worldwide	5,911	2,058	3,201	1,930	2,594	776		

2009

United States	4,806	1,788	5,158	3,569	2,447	734
Equatorial Guinea	-	-	13	9	5	3
Other Africa	976	160	-	-	91	15
Total Africa	976	160	13	9	96	18
Total Europe	67	27	44	18	27	10
Worldwide	5,849	1,975	5,215	3,596	2,570	762

(a) Of the gross productive wells, wells with multiple completions operated by us totaled 168, 164 and 170 as of December 31, 2011, 2010 and 2009. Information on wells with multiple completions operated by others is unavailable to us.

(b) As operations were resuming in Libya at December 31, 2011, an accurate count of productive wells was not possible; therefore no Libyan wells are included in this number. Production from Libya at December 31, 2011 was approximately 30 percent of the 45 mboed pre-conflict level.

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Drilling Activity

For our E&P segment, the following table sets forth, by geographic area, the number of net productive and dry development and exploratory wells completed in each of the last three years.

	Development				Exploratory				Total
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	
2011									
United States	46	17	3	66	37	4	1	42	108
Total Africa[a]	2	-	-	2	-	-	-	-	2
Total Europe	2	-	-	2	-	-	-	-	2
Total Other International	-	-	-	-	-	-	1	1	1
Worldwide	50	17	2	70	37	4	2	43	113
2010									
United States	35	46	1	82	20	11	3	34	116
Total Africa	5	-	-	5	1	-	-	1	6
Total Europe	2	-	-	2	-	-	-	-	2
Total Other International	-	-	-	-	1	-	1	2	2
Worldwide	42	46	1	89	22	11	4	37	126
2009									
United States	11	54	2	67	37	9	2	48	115
Total Africa	5	1	-	6	-	-	-	-	6
Total Europe	1	-	-	1	1	-	-	1	2
Worldwide	17	55	2	74	38	9	2	49	123

(a) Activity in Libya through February 2011.

Acreage

We believe we have satisfactory title to our properties in accordance with standards generally accepted in the industry; nevertheless, we can be involved in title disputes from time to time which may result in litigation. In the case of undeveloped properties, an investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. Our title to properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the industry. In addition, our interests may be subject to obligations or duties under applicable laws or burdens such as net profits interests, liens related to operating agreements, development obligations or capital commitments under international PSCs or exploration licenses.

The following table sets forth, by geographic area, the gross and net developed and undeveloped exploration and production acreage held in our E&P segment as of December 31, 2011.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
United States	1,620	1,215	1,449	1,143	3,069	2,358
Canada	-	-	143	55	143	55
Total North America	1,620	1,215	1,592	1,198	3,212	2,413
Equatorial Guinea	45	29	92	69	137	98
Other Africa	12,909	2,108	2,580	258	15,489	2,366

Total Africa	12,954	2,137	2,672	327	15,626	2,464
Total Europe	131	68	3,173	1,449	3,304	1,517
Other International	-	-	3,985	2,334	3,985	2,334
Worldwide	14,705	3,420	11,422	5,308	26,127	8,728

Of the 5.3 million net undeveloped acres held at December 31, 2011, 15 percent, 9 percent and 20 percent of those acres are under agreements scheduled to expire in the years 2012, 2013, and 2014.

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Marketing Activities

Our E&P segment includes activities related to the marketing and transportation of substantially all of our liquid hydrocarbon and natural gas production. These activities include the transportation of production to market centers, the sale of commodities to third parties and storage of production. We balance our various sales, storage and transportation positions through what we call supply optimization, which can include the purchase of commodities from third parties for resale. Supply optimization serves to aggregate volumes in order to satisfy transportation commitments thereby optimizing transportation capacity and value and to achieve flexibility within product types and delivery points.

Oil Sands Mining Segment

We hold a 20 percent outside-operated interest in the AOSP, an oil sands mining joint venture located in Alberta, Canada. The joint venture produces bitumen from oil sands deposits in the Athabasca region utilizing mining techniques and upgrades the bitumen to synthetic crude oils. The AOSP s mining and extraction assets are located near Fort McMurray, Alberta and include the Muskeg River and the Jackpine mines. Gross design capacity of the combined mines is 255,000 (51,000 net to our interest) barrels of bitumen per day. As of December 31, 2011, we own or have rights to participate in developed and undeveloped leases totaling approximately 216,000 gross (43,000 net) acres. The underlying developed leases are held for the duration of the project, with royalties payable to the province of Alberta. The upgrading assets are located at Fort Saskatchewan, northeast of Edmonton, Alberta.

The five year AOSP Expansion 1 was completed in 2011. The Jackpine mine commenced production under a phased start-up in the third quarter of 2010 and began supplying oil sands ore to the base processing facility in the fourth quarter of 2010. The upgrader expansion was completed and commenced operations in the second quarter of 2011. Synthetic crude oil sales volumes for 2011 were 43 mbbld, with production of 38 mbbld. Phase one of debottlenecking opportunities was approved in 2011 and potential future expansions and additional debottlenecking opportunities remain under review.

Current AOSP operations use established processes to mine oil sands deposits from an open-pit mine, extract the bitumen and upgrade it into synthetic crude oils. Ore is mined using traditional truck and shovel mining techniques. The mined ore passes through primary crushers to reduce the ore chunks in size and is then sent to rotary breakers where the ore chunks are further reduced to smaller particles. The particles are combined with hot water to create slurry. The slurry moves through the extraction process where it separates into sand, clay and bitumen-rich froth. A solvent is added to the bitumen froth to separate out the remaining solids, water and heavy asphaltenes. The solvent washes the sand and produces clean bitumen that is required for the upgrader to run efficiently. The process yields a mixture of solvent and bitumen which is then transported from the mine to the Scotford upgrader via the approximately 300 mile Corridor Pipeline.

The bitumen is upgraded at Scotford using both hydrotreating and hydroconversion processes to remove sulfur and break the heavy bitumen molecules into lighter products. Blendstocks acquired from outside sources are utilized in the production of our saleable products. The upgrader produces synthetic crude oil and vacuum gas oil. The vacuum gas oil is sold to an affiliate of the operator under a long term contract at market-related prices, and the other products are sold in the marketplace.

As announced in the second quarter of 2011, the governments of Alberta and Canada have agreed to partially fund Quest CCS for 865 million Canadian dollars. Financing would be received over a period of 15 years, including development, construction and 10 years of operations. However, the funding is subject to conditions of achieving certain performance objectives. We expect a final investment decision on this project in 2012.

The above discussions include forward-looking statements with respect to Quest CCS. Some factors that could potentially affect these forward-looking statements include projected costs and satisfaction of remaining conditions necessary for final investment decision. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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Reserves

Estimated Reserve Quantities

The following table sets forth estimated quantities of our net proved liquid hydrocarbon, natural gas and synthetic crude oil reserves based upon an unweighted average of closing prices for the first day of each month in the 12-month periods ended December 31, 2011, 2010 and 2009. Approximately 65 percent of our proved reserves are located in Organization for Economic Cooperation and Development (OECD) countries.

Reserves are disclosed by continent, by country, if the proved reserves related to any geographic area, on an oil-equivalent barrel basis represent 15 percent or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent, or a continent.

	North America			Africa			Europe	
December 31, 2011	United States	Canada	Total	EG	Other	Total	Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbons *(mmbbl)*	141	-	141	78	179	257	84	482
Natural gas *(bcf)*	551	-	551	1,104	104	1,208	40	1,799
Synthetic crude oil *(mmbbl)*	-	623	623	-	-	-	-	623
Total proved developed reserves *(mmboe)*	233	623	856	262	196	458	91	1,405
Proved Undeveloped Reserves								
Liquid hydrocarbons *(mmbbl)*	138	-	138	39	61	100	13	251
Natural gas *(bcf)*	321	-	321	467	-	467	79	867
Total proved undeveloped reserves *(mmboe)*	191	-	191	117	61	178	26	395
Total Proved Reserves								
Liquid hydrocarbons *(mmbbl)*	279	-	279	117	240	357	97	733
Natural gas *(bcf)*	872	-	872	1,571	104	1,675	119	2,666
Synthetic crude oil *(mmbbl)*	-	623	623	-	-	-	-	623
Total proved reserves *(mmboe)*	424	623	1,047	379	257	636	117	1,800

	North America			Africa			Europe	
December 31, 2010	United States	Canada	Total	EG	Other	Total	Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbons *(mmbbl)*	124	-	124	86	180	266	89	479
Natural gas *(bcf)*	591	-	591	1,186	104	1,290	43	1,924
Synthetic crude oil *(mmbbl)*	-	433	433	-	-	-	-	433
Total proved developed reserves *(mmboe)*	222	433	655	284	198	482	96	1,233
Proved Undeveloped Reserves								
Liquid hydrocarbons *(mmbbl)*	49	-	49	33	59	92	10	151
Natural gas *(bcf)*	154	-	154	465	1	466	73	693
Synthetic crude oil *(mmbbl)*	-	139	139	-	-	-	-	139
Total proved undeveloped reserves *(mmboe)*	75	139	214	110	59	169	22	405
Total Proved Reserves								
Liquid hydrocarbons *(mmbbl)*	173	-	173	119	239	358	99	630
Natural gas *(bcf)*	745	-	745	1,651	105	1,756	116	2,617
Synthetic crude oil *(mmbbl)*	-	572	572	-	-	-	-	572
Total proved reserves *(mmboe)*	297	572	869	394	257	651	118	1,638

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	North America			Africa			Europe	
December 31, 2009	United States	Canada	Total	EG	Other	Total	Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbons *(mmbbl)*	120	-	120	83	186	269	87	476
Natural gas *(bcf)*	652	-	652	1,102	107	1,209	50	1,911
Synthetic crude oil *(mmbbl)*	-	392	392	-	-	-	-	392
Total proved developed reserves *(mmboe)*	229	392	621	267	204	471	95	1,187
Proved Undeveloped Reserves								
Liquid hydrocarbons *(mmbbl)*	50	-	50	39	42	81	15	146
Natural gas *(bcf)*	168	-	168	586	-	586	59	813
Synthetic crude oil *(mmbbl)*	-	211	211	-	-	-	-	211
Total proved undeveloped reserves *(mmboe)*	78	211	289	136	42	178	25	492
Total Proved Reserves								
Liquid hydrocarbons *(mmbbl)*	170	-	170	122	228	350	102	622
Natural gas *(bcf)*	820	-	820	1,688	107	1,795	109	2,724
Synthetic crude oil *(mmbbl)*	-	603	603	-	-	-	-	603
Total proved reserves *(mmboe)*	307	603	910	403	246	649	120	1,679

The significant increase in proved reserves from 2010 to 2011 was primarily due to the Eagle Ford shale acquisitions. Also, synthetic crude oil reserves increased, primarily because of the inclusion of additional lease portions in the Jackpine mine and technical and economic reevaluations at year end.

The above estimated quantities of net proved liquid hydrocarbon and natural gas reserves are forward-looking statements and are based on a number of assumptions, including (among others) commodity prices, presently known physical data concerning size and character of the reservoirs, economic recoverability, technology developments, future drilling success, industry economic conditions, levels of cash flow from operations, production experience and other operating considerations. The above estimated quantities of synthetic crude oil reserves are forward-looking statements and are based on presently known physical data, economic recoverability and operating conditions. To the extent these assumptions prove inaccurate, actual recoveries and development costs could be different than current estimates. For additional details of the estimated quantities of proved reserves at the end of each of the last three years, see Item 8. Financial Statements and Supplementary Data Supplementary Information on Oil and Gas Producing Activities.

Preparation of Reserve Estimates

Our estimation of economically producible volumes of liquid hydrocarbons and natural gas is a highly technical process performed primarily by in-house teams of reservoir engineers and geoscience professionals. All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X. Liquid hydrocarbon, natural gas and synthetic crude oil reserve estimates are reviewed and approved by our Corporate Reserves Group, which includes our Director of Corporate Reserves and her staff of Coordinators. Reserve estimates are developed and reviewed by Qualified Reserve Estimators (QRE). QREs are engineers or geoscientists with a minimum of a Bachelor of Science degree in the appropriate technical field, have a minimum of three years of industry experience with at least one year in reserve estimation and have completed Marathon Oil s Qualified Reserve Estimator training course. The Reserve Coordinators review all reserve estimates for all fields with proved reserves greater than 3 mmboe at a minimum of once every three years. Any change to proved reserve estimates in excess of 2.5 mmboe on a total field basis, within a single month, must be approved by Corporate Reserves Group management. All other proved reserve changes must be approved by a Reserve Coordinator.

Our Director of Corporate Reserves, who reports to our Chief Financial Officer, has a Bachelor of Science degree in petroleum engineering and a Master of Business Administration. Her 37 years of experience in the industry include 26 with Marathon Oil. She is active in industry and professional groups, having served on the Society of Petroleum Engineers (SPE) Oil and Gas Reserves Committee (OGRC), chairing in 2008 and 2009. As a member of the OGRC, she participated in the development of the Petroleum Resource Management System. She chaired the development of the OGRC comments on the SEC s proposed modernization of oil and gas reporting and was a member of the American Petroleum Institute s Ad Hoc group that provided comments on the same topic.

Estimates of synthetic crude oil reserves are prepared by GLJ Petroleum Consultants of Calgary, Canada, third-party consultants. Their reports for all years are filed as exhibits to this Annual Report on Form 10-K. The engineer responsible

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for the estimates of our oil sands mining reserves has 33 years of experience in petroleum engineering and has conducted surface mineable oil sands evaluations since 1986. He is a member of SPE, having served as regional director from 1998 through 2001 and is a registered Practicing Professional Engineer in the Province of Alberta.

Audits of Estimates

Third-party consultants are engaged to provide independent estimates for fields that comprise 80 percent of our total proved reserves over a rolling four-year period for the purpose of auditing the in-house reserve estimates. We met this goal for the four-year period ended December 31, 2011. We established a tolerance level of 10 percent such that initial estimates by the third-party consultants are accepted if they are within 10 percent of our internal estimates. Should the third-party consultants initial analysis fail to reach our tolerance level, both our team and the consultants re-examine the information provided, request additional data and refine their analysis if appropriate. This resolution process is continued until both estimates are within 10 percent. This process did not result in significant changes to our reserve estimates in 2011 or 2009. There were no third-party audits performed in 2010.

During 2011, Netherland, Sewell & Associates, Inc. (NSAI) prepared a Certification of December 31, 2010 reserves for the Alba field in Equatorial Guinea. The NSAI summary report is filed as an exhibit to this Annual Report on Form 10-K. The senior members of the NSAI team have over 50 years of industry experience between them, having worked for large, international oil and gas companies before joining NSAI. The team lead has a Master of Science in mechanical engineering and is a member of SPE. The senior technical advisor has a Bachelor of Science degree in geophysics and is a member of the Society of Exploration Geophysicists, the American Association of Petroleum Geologists and the European Association of Geoscientists and Engineers. Both are licensed in the state of Texas.

Ryder Scott Company (Ryder Scott) performed audits of several of our fields in 2011 and 2009. Their summary report on audits performed in 2011 is filed as an exhibit to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 20 years of industry experience, having worked for a major international oil and gas company before joining Ryder Scott. He has a Bachelor of Science degree in mechanical engineering, is a member of SPE and is a registered Professional Engineer in the state of Texas.

The Corporate Reserves Group also performs separate, detailed technical reviews of reserve estimates for significant fields that were acquired recently or for properties with other indicators such as excessively short or long lives, performance above or below expectations or changes in economic or operating conditions.

Changes in Proved Undeveloped Reserves

As of December 31, 2011, 395 mmboe of proved undeveloped reserves were reported, a decrease of 10 mmboe from December 31, 2010. The following table shows changes in total proved undeveloped reserves for 2011:

Beginning of year	405
Revisions of previous estimates	15
Improved recovery	1
Purchases of reserves in place	91
Extensions, discoveries, and other additions	49
Transfer to Proved Developed	(166)
End of year	395

Significant additions to proved undeveloped reserves during 2011 include 91 mmboe due to acreage acquisition in the Eagle Ford shale, 26 mmboe related to Anadarko Woodford shale development, 10 mmboe for development drilling in the Bakken shale play and 8 mmboe for additional drilling in Norway. Additionally, 139 mmboe were transferred from proved undeveloped to proved developed reserves due to startup of the Jackpine upgrader expansion in Canada. Costs incurred in 2011, 2010 and 2009 relating to the development of proved undeveloped reserves, were $1,107 million, $1,463 million and $792 million.

Projects can remain in proved undeveloped reserves for extended periods in certain situations such as behind-pipe zones where reserves will not be accessed until the primary producing zone depletes, large development projects which take more than five years to complete, and the timing of when additional gas compression is needed. Of the 395 mmboe of proved undeveloped reserves at year end 2011, 34 percent of the volume is associated with projects that have been included in proved reserves for more than five years. The majority of this volume is related to a compression project in Equatorial Guinea that was sanctioned by our Board of Directors in 2004 and is expected to be completed by 2016.

Performance of this field has exceeded expectations, and estimates of initial dry gas in place increased by roughly 10 percent between 2004 and 2010. Production is not expected to experience a natural decline from facility-limited plateau production until 2014, or possibly 2015. The timing of the installation of compression is being driven by the reservoir performance.

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Proved undeveloped reserves for the North Gialo project, located in the Libyan Sahara desert, were booked for the first time as proved undeveloped reserves in 2010. This project, which is anticipated to take more than five years to be developed, is being executed by the operator and encompasses a continuous drilling program including the design, fabrication and installation of extensive liquid handling and gas recycling facilities. In 2010, an engineering firm was awarded the front-end engineering and design activities. The remoteness of the North Gialo project is expected to extend the duration of project execution more than five years after the reserves were initially booked. For example, lead time for delivery of required highly specialized compressors is approximately 24 months. There are no other significant undeveloped reserves expected to be developed more than five years after their original booking.

As of December 31, 2011, future development costs estimated to be required for the development of proved undeveloped liquid hydrocarbon, natural gas and synthetic crude oil reserves for the years 2012 through 2016 are projected to be $2,023 million, $1,537 million, $1,229 million, $804 million, and $439 million.

The timing of future projects and estimated future development costs relating to the development of proved undeveloped liquid hydrocarbons, natural gas and synthetic crude oil reserves are forward-looking statements and are based on a number of assumptions, including (among others) commodity prices, presently known physical data concerning size and character of the reservoirs, economic recoverability, technology developments, future drilling success, industry economic conditions, levels of cash flow from operations, production experience and other operating considerations. To the extent these assumptions prove inaccurate, actual recoveries, timing and development costs could be different than current estimates.

Net Production Sold

	North America			Africa			Europe		
	United States	Canada[(a)]	Total	EG	Other	Total	Total	Disc. Ops[(b)]	Total
Year Ended December 31, 2011									
Liquid hydrocarbons *(mbbld)*[(c)]	75	-	75	38	5	43	101	-	219
Natural gas *(mmcfd)*[(d)(e)]	326	-	326	443	-	443	81	-	850
Synthetic crude oil *(mbbld)*	-	38	38	-	-	-	-	-	38
Total production sold *(mboed)*	129	38	167	112	5	117	115	-	399
Year Ended December 31, 2010									
Liquid hydrocarbons *(mbbld)*[(c)]	70	-	70	38	45	83	92	-	245
Natural gas *(mmcfd)*[(d)(e)]	364	-	364	405	4	409	87	-	860
Synthetic crude oil *(mbbld)*	-	24	24	-	-	-	-	-	24
Total production sold *(mboed)*	131	24	155	106	45	151	106	-	412
Year Ended December 31, 2009									
Liquid hydrocarbons *(mbbld)*[(c)]	64	-	64	42	45	87	92	5	248
Natural gas *(mmcfd)*[(d)(e)]	373	-	373	426	4	430	116	17	936
Total production sold *(mboed)*	126	-	126	113	46	159	111	7	403

(a) Before December 31, 2009, reserves related to OSM were not included in the SEC s definition of oil and gas producing activities; therefore, synthetic crude oil production of 27 mbbld is not reported for 2009.

(b) Our businesses in Ireland and Gabon were sold in 2009 and were reported as discontinued operations.

(c) Includes crude oil, condensate and natural gas liquids. The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(d) U.S. natural gas volumes exclude volumes produced in Alaska that are stored for later sale in response to seasonal demand, although our reserves have been reduced by those volumes.

(e) Excludes volumes acquired from third parties for injection and subsequent resale.

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Average Sales Price per Unit

	North America			Africa			Europe		
(Dollars per unit)	United States	Canada[a]	Total	EG	Other	Total	Total	Disc. Ops[b]	Total
Year Ended December 31, 2011									
Liquid hydrocarbons *(bbl)*	$ 92.55	-	$ 92.55	$ 67.70	$ 112.56	$ 73.21	$ 115.55	$ -	$ 99.37
Natural gas *(mcf)*	4.95	-	4.95	0.24	0.70	0.24	9.75	-	2.96
Synthetic crude oil *(bbl)*	-	91.65	91.65	-	-	-	-	-	91.65
Year Ended December 31, 2010									
Liquid hydrocarbons *(bbl)*	$ 72.30	-	$ 72.30	$ 50.57	$ 89.15	$ 71.71	$ 81.95	$ -	$ 75.73
Natural gas *(mcf)*	4.71	-	4.71	0.24	0.70	0.25	7.04	-	2.82
Synthetic crude oil *(bbl)*	-	71.06	71.06	-	-	-	-	-	71.06
Year Ended December 31, 2009									
Liquid hydrocarbons *(bbl)*	$ 54.67	-	$ 54.67	$ 38.06	$ 68.41	$ 53.91	$ 64.46	$ 56.47	$ 58.06
Natural gas *(mcf)*	4.14	-	4.14	0.24	0.70	0.25	4.84	8.54	2.52

(a) Before December 31, 2009, OSM was not included in the SEC s definition of oil and gas producing activities; therefore, synthetic crude oil prices are not reported for 2009.

(b) Our businesses in Ireland and Gabon were sold in 2009 and were reported as discontinued operations.

Average Production Cost per Unit[a]

	North America			Africa			Europe		
(Dollars per boe)	United States	Canada[b]	Total	EG	Other[c]	Total	Total	Disc. Ops[d]	Grand Total
Years ended December 31:									
2011	$ 16.42	$ 55.65	$ 25.68	$ 2.87	$ 17.16	$ 3.53	$ 8.24	$ -	$ 14.26
2010	14.16	65.15	22.36	2.81	4.18	3.23	7.49	-	11.54
2009	14.03	-	14.03	2.63	3.64	2.93	6.99	19.14	7.80

(a) Production, severance and property taxes are excluded from the production costs used in the calculation of this metric.

(b) Before December 31, 2009 OSM was not included in the SEC s definition of oil and gas producing activities; therefore, production costs are not reported for 2009. Production costs in 2010 include costs associated with a major turnaround and $64 million for a water abatement accrual in 2011.

(c) Production operations ceased in Libya in February 2011, but fixed costs continued to be incurred.

(d) Our businesses in Ireland and Gabon were sold in 2009 and were reported as discontinued operations.

Integrated Gas

Our integrated gas operations include natural gas liquefaction operations and methanol production operations. Also included in the financial results of the Integrated Gas segment are the costs associated with ongoing development of projects to link stranded natural gas resources with key demand areas.

We hold a 60 percent interest in EGHoldings, which is accounted for under the equity method of accounting. EGHoldings has a 3.7 mmta LNG production facility on Bioko Island in EG. LNG from the production facility is sold under a 3.4 mmta, or 460 mmcfd, sales and purchase agreement with a 17-year term ending in 2024. The purchaser under the agreement takes delivery of the LNG on Bioko Island, with pricing linked principally to the Henry Hub index, regardless of destination. This production facility allows us to monetize our natural gas reserves from the Alba field, as natural gas for the facility is purchased from the Alba field participants under a long-term natural gas supply agreement. Gross sales of LNG from this production facility totaled 4.1 mmt in 2011. Planned maintenance at the LNG production facility is scheduled for a 30 day period from late first quarter through early second quarter 2012, with operations expected to be completely shut down for 10 of those days. In 2011, we continued discussions with the government of EG and our partners regarding a potential second LNG production train on Bioko Island.

We own a 45 percent interest in AMPCO, which is accounted for under the equity method of accounting. AMPCO owns a methanol plant located on Bioko Island in Equatorial Guinea. Feedstock for the plant is supplied from our natural gas production from the Alba field. Gross sales of methanol from the plant totaled 1.04, 0.85 and 0.96 mmt in 2011, 2010 and 2009. Production from the plant is used to supply customers in Europe and the U.S.

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We sold our 30 percent outside-operated interest in a natural gas liquefaction plant in Kenai Alaska in the third quarter of 2011 at which time our sales from this facility ceased.

The above discussion of the Integrated Gas segment contains forward-looking statements with respect to the planned maintenance and possible expansion of the LNG production facility in Equatorial Guinea. Factors that could potentially affect the possible expansion of the LNG production facility include partner and government approvals, access to sufficient natural gas volumes through exploration or commercial negotiations with other resource owners and access to sufficient regasification capacity. Predicted planned maintenance and downtime are good faith estimates and preliminary, and therefore, subject to change. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Competition and Market Conditions

Strong competition exists in all sectors of the oil and gas industry and, in particular, in the exploration for and development of new reserves. We compete with major integrated and independent oil and gas companies, as well as national oil companies, for the acquisition of oil and natural gas leases and other properties. We compete with these companies for the equipment and labor required to develop and operate those properties and in the marketing of oil and natural gas to end-users. Many of our competitors have financial and other resources greater than those available to us. Acquiring exploration opportunities frequently requires competitive bids involving front-end bonus payments or commitments-to-work programs. We also compete in attracting and retaining personnel, including petroleum engineers, geologists, geophysicists and other specialists. Based upon statistics compiled in the 2011 Global Upstream Performance Review published by IHS Herold Inc., we rank tenth among U.S.-based petroleum companies on the basis of 2010 worldwide liquid hydrocarbon and natural gas production.

We also compete with other producers of synthetic and conventional crude oil for the sale of our synthetic crude oil to refineries primarily in North America. Additional synthetic crude oil projects are being contemplated by various competitors and, if undertaken and completed, these projects may result in a significant increase in the supply of synthetic crude oil to the market. Since not all refineries are able to process or refine synthetic crude oil in significant volumes, there can be no assurance that sufficient market demand will exist at all times to absorb our share of the synthetic crude oil production from the AOSP at economically viable prices.

Our operating results are affected by price changes in conventional and synthetic crude oil, natural gas and petroleum products, as well as changes in competitive conditions in the markets we serve. Generally, results from production and oil sands mining operations benefit from higher crude oil prices. Market conditions in the oil and gas industry are cyclical and subject to global economic and political events and new and changing governmental regulations. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, Overview Market Conditions for additional discussion of the impact of prices on our operations.

Environmental, Health and Safety Matters

The Health, Environmental, Safety and Corporate Responsibility Committee of our Board of Directors is responsible for overseeing our position on public issues, including environmental, health and safety matters. Our Corporate Health, Environment, Safety and Security organization has the responsibility to ensure that our operating organizations maintain environmental compliance systems that support and foster our compliance with applicable laws and regulations. Committees comprised of certain of our officers review our overall performance associated with various environmental compliance programs. We also have a Corporate Emergency Response Team which oversees our response to any major environmental or other emergency incident involving us or any of our properties.

Our businesses are subject to numerous laws and regulations relating to the protection of the environment, health and safety. These laws and regulations include the Occupational Safety and Health Act (OSHA) with respect to the protection of health and safety of employees, the Clean Air Act (CAA) with respect to air emissions, the Federal Water Pollution Control Act (also known as the Clean Water Act (CWA) with respect to water discharges, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) with respect to releases and remediation of hazardous substances, the Oil Pollution Act of 1990 (OPA-90) with respect to oil pollution and response, the National Environmental Policy Act with respect to evaluation of environmental impacts, the Endangered Species Act with respect to the protection of endangered or threatened species, the Resource Conservation and Recovery Act (RCRA) with respect to solid and hazardous waste treatment, storage and disposal, and the U.S. Emergency Planning and Community Right-to-Know Act with respect to the dissemination of information relating to certain chemical inventories. In addition, many other states and countries in which where we operate have their own similar laws dealing with similar matters.

These laws and regulations could result in costs to remediate releases of regulated substances, including crude oil, into the environment, or costs to remediate sites to which we sent regulated substances for disposal. In some cases, these

laws can impose liability for the entire cost of clean-up on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others (such as prior owners or operators of our assets) or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. New laws have been enacted and regulations are being adopted by various regulatory agencies on a continuing basis and the costs of compliance with these new rules can only be broadly appraised until their implementation becomes more defined. Based on regulatory trends, particularly with respect to the CAA and its implementing regulations, we have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes.

For a discussion of environmental capital expenditures and costs of compliance for air, water, solid waste and remediation, see Item 3. Legal Proceedings and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Management s Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

Air

In August 2011, the U.S. Environmental Protection Agency (U.S. EPA) published proposed New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that will both amend existing NSPS and NESHAP standards for oil and gas facilities as well as create a new NSPS for oil and gas production, transmission and distribution facilities. If the proposed rules are finalized without substantial modification, compliance with the rules will result in an increase in costs of control, equipment and labor and require additional notification, monitoring, reporting and recordkeeping. The U.S. EPA is required to finalize this rule by April, 2012.

In July 2011, the U.S. EPA finalized a Federal Implementation Plan under the CAA that includes New Source Review (NSR) regulations which apply to air emissions sources on Tribal Lands. This rule became effective on August 30, 2011, and requires the registration and/or pre-construction permitting of most of our facilities on Tribal Lands in Wyoming, Oklahoma and North Dakota. To minimize pre-construction delays in the near term, we entered into an Administrative Compliance and Consent Agreement (Agreement) that temporarily suspended the requirement for pre-construction permits for facilities on Trial Lands in North Dakota as long as permit applications were filed in accordance with the Agreement. We cannot reasonably estimate the financial impact of these permitting requirements until the U.S. EPA finalizes its internal permitting procedures. The U.S. EPA has indicated that this rule will be finalized during the first half of 2012.

Climate Change

In 2010, the U.S. EPA promulgated rules that required us to monitor and submit an annual report on our greenhouse gas emissions. Further, state, national and international requirements to reduce greenhouse emissions are being proposed and in some cased promulgated. These requirements apply or could apply in countries in which we operate. Potential legislation and regulations pertaining to climate change could also affect our operations. The cost to comply with these laws and regulations cannot be estimated at this time. For additional information, see Item 1A. Risk Factors. As part of our commitment to environmental stewardship, we estimate and publicly report greenhouse gas emissions from our operations. We are working to continuously improve the accuracy and completeness of these estimates. In addition, we continuously strive to improve operational and energy efficiencies through resource and energy conservation where practicable and cost effective.

Hydraulic Fracturing

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Hydraulic fracturing has been regulated at the state level through permitting and compliance requirements. State level initiatives in regions with substantial shale resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. In addition, the U.S. Congress has considered legislation that would require regulation affecting the hydraulic fracturing process. In the first quarter of 2010, the U.S. EPA announced its intention to conduct a comprehensive research study on the potential effects that hydraulic fracturing may have on water quality and public health. The U.S. EPA has begun preparation for the study and expects to issue an interim report in 2012 followed by a final report in 2014.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal or state laws or the

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implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs, which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells.

Remediation

The AOSP operations use established processes to mine deposits of bitumen from an open-pit mine, extract the bitumen and upgrade it into synthetic crude oils. Tailings are waste products created from the oil sands extraction process which are placed in ponds. The AOSP is required to reclaim its tailing ponds as part of its ongoing reclamation work. The reclamation process uses developing technology and there is an inherent risk that the current process may not be as effective or perform as required in order to meet the approved closure and reclamation plan. The AOSP continues to develop its current reclamation technology and continues to investigate alternate tailings management technologies. In February 2009, the Alberta Energy Resources Conservation Board (ERCB) issued a Directive which more clearly defines criteria for managing oil sands tailings. The AOSP joint venture operator submitted tailings management papers to the ERCB for both mines setting forth plans to comply with the Directive which received approval, with conditions, in the second half of 2010. Further new regulations or failure to comply in a timely manner could result in additional cost to us.

Concentrations of Credit Risk

We are exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. For the years 2011, 2010 and 2009, transactions with MPC accounted for more than 10 percent of our annual revenues. The majority of those transactions occurred while MPC was a wholly-owned subsidiary. In addition, for the years 2010 and 2009, sales of crude oil to the Libyan National Oil Company accounted for more than 10 percent of our annual revenues. These transactions were restricted to sales of crude oil produced in Libya during those periods.

Trademarks, Patents and Licenses

We currently hold a number of U.S. and foreign patents and have various pending patent applications. Although in the aggregate our trademarks, patents and licenses are important to us, we do not regard any single trademark, patent, license or group of related trademarks, patents or licenses as critical or essential to our business as a whole.

Employees

We had 3,322 active, full-time employees as of December 31, 2011. We consider labor relations with our employees to be satisfactory. We have not had any work stoppages or strikes pertaining to our employees.

Executive Officers of the Registrant

The executive officers of Marathon Oil and their ages as of February 1, 2012, are as follows:

Clarence P. Cazalot, Jr.	61	Chairman, President and Chief Executive Officer
Janet F. Clark	57	Executive Vice President and Chief Financial Officer
David E. Roberts, Jr.	51	Executive Vice President and Chief Operating Officer
Eileen M. Campbell	54	Vice President, Public Policy
Steven P. Guidry	53	Vice President, Business Development
Sylvia J. Kerrigan	46	Vice President, General Counsel and Secretary
Michael K. Stewart	54	Vice President, Finance and Accounting, Controller and Treasurer
Howard J. Thill	52	Vice President, Investor Relations and Public Affairs

All of the executive officers have held responsible management or professional positions with Marathon Oil or its subsidiaries for more than the past five years.

Mr. Cazalot was appointed chairman of the board of directors effective July 2011 and was appointed president and chief executive officer effective January 2002.

Ms. Clark was appointed executive vice president effective January 2007. Ms. Clark joined Marathon Oil in January 2004 as senior vice president and chief financial officer.

Mr. Roberts was appointed executive vice president and chief operating officer effective July 2011. Mr. Roberts joined Marathon in June 2006 as senior vice president, business development and was appointed executive vice president, upstream in April 2008.

Ms. Campbell was appointed vice president, public policy effective June 2010. Prior to this appointment, Ms. Campbell was Vice President, Human Resources since October 2000.

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Mr. Guidry was appointed vice president, business development effective July 2011. Mr. Guidry previously served as regional vice president for our Libya operations from November 2008 to June 2011. Prior to the Libya assignment, Mr. Guidry was regional vice president for Marathon s North American Production Operations from August 2006 to November 2008.

Ms. Kerrigan was appointed vice president, general counsel and secretary effective November 1, 2009. Prior to this appointment, Ms. Kerrigan was assistant general counsel since January 1, 2003.

Mr. Stewart was appointed vice president, finance and accounting, controller and treasurer effective December 2011. Mr. Stewart previously served as vice president, accounting and controller from May 2006 to December 2011 and as controller from July 2005 to April 2006.

Mr. Thill was appointed vice president, investor relations and public affairs effective January 2008. Mr. Thill was previously director of investor relations from April 2003 to December 2007.

Available Information

General information about Marathon Oil, including the Corporate Governance Principles and Charters for the Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and Health, Environmental, Safety and Corporate Responsibility Committee, can be found at www.marathonoil.com. In addition, our Code of Business Conduct and Code of Ethics for Senior Financial Officers are available at http://www.marathonoil.com/Investor_Center/.

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. These documents are also available in hard copy, free of charge, by contacting our Investor Relations office. Information contained on our website is not incorporated into this Annual Report on Form 10-K or other securities filings.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations.

A substantial or extended decline in liquid hydrocarbon or natural gas prices would reduce our operating results and cash flows and could adversely impact our future rate of growth and the carrying value of our assets.

Prices for liquid hydrocarbons and natural gas fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our liquid hydrocarbons and natural gas. Historically, the markets for liquid hydrocarbons and natural gas have been volatile and may continue to be volatile in the future. Many of the factors influencing prices of liquid hydrocarbons and natural gas are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for liquid hydrocarbons and natural gas;
- the cost of exploring for, developing and producing liquid hydrocarbons and natural gas;
- the ability of the members of OPEC to agree to and maintain production controls;
- political instability or armed conflict in oil and natural gas producing regions;

- changes in weather patterns and climate;
- natural disasters such as hurricanes and tornados;
- the price and availability of alternative and competing forms of energy;
- domestic and foreign governmental regulations and taxes; and
- general economic conditions worldwide.

The long-term effects of these and other factors on the prices of liquid hydrocarbons and natural gas are uncertain.

Lower liquid hydrocarbon and natural gas prices may cause us to reduce the amount of these commodities that we produce, which may reduce our revenues, operating income and cash flows. Significant reductions in liquid hydrocarbon and natural gas prices could require us to reduce our capital expenditures or impair the carrying value of our assets.

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Our offshore operations involve special risks that could negatively impact us.

Offshore exploration and development operations present technological challenges and operating risks because of the marine environment. Activities in deepwater areas may pose incrementally greater risks because of water depths that limit intervention capability and the physical distance to oilfield service infrastructure and service providers. Environmental remediation and other costs resulting from spills or releases may result in substantial liabilities.

Estimates of liquid hydrocarbon, natural gas and synthetic crude oil reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our liquid hydrocarbon, natural gas and synthetic crude oil reserves.

The proved reserve information included in this Report has been derived from engineering estimates. Estimates of liquid hydrocarbon and natural gas reserves were prepared by our in-house teams of reservoir engineers and geoscience professionals and were reviewed, on a selected basis, by our Corporate Reserves Group. The synthetic crude oil reserves estimates were prepared by GLJ Petroleum Consultants, a third-party consulting firm experienced in working with oil sands. Reserves were valued based on the unweighted average of closing prices for the first day of each month in the 12-month period ended December 31, 2011, as well as other conditions in existence at the date. Any significant future price change will have a material effect on the quantity and present value of our proved reserves. Future reserve revisions could also result from changes in governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of liquid hydrocarbons, natural gas and bitumen that cannot be directly measured. (Bitumen is mined and then upgraded into synthetic crude oil.) Estimates of economically producible reserves and of future net cash flows depend on a number of variable factors and assumptions, including:

- location, size and shape of the accumulation as well as fluid, rock and producing characteristics of the accumulation;
- historical production from the area, compared with production from other comparable producing areas;
- volumes of bitumen in-place and various factors affecting the recoverability of bitumen and its conversion into synthetic crude oil such as historical upgrader performance;
- the assumed effects of regulation by governmental agencies;
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and repair costs; and
- industry economic conditions, levels of cash flows from operations and other operating considerations.

As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of proved reserves and future net cash flows based on the same available data. Because of the subjective nature of such reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of production;
- the revenues and costs associated with that production; and

the amount and timing of future development expenditures.

The discounted future net revenues from our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves reflected in this Report should not be considered as the market value of the reserves attributable to our properties. As required by SEC Rule 4-10 of Regulation S-X, the estimated discounted future net revenues from our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves are based on an unweighted average of closing prices for the first day of each month in the 12-month period ended December 31, 2011, and costs applicable at the date of the estimate, while actual future prices and costs may be materially higher or lower.

In addition, the 10 percent discount factor required by the applicable rules of the SEC to be used to calculate discounted future net revenues for reporting purposes is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the oil and natural gas industry in general.

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If we are unsuccessful in acquiring or finding additional reserves, our future liquid hydrocarbon and natural gas production would decline, thereby reducing our cash flows and results of operations and impairing our financial condition.

The rate of production from liquid hydrocarbon and natural gas properties generally declines as reserves are depleted. Except to the extent we acquire interests in additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, optimize production performance, identify additional reservoirs not currently producing or secondary recovery reserves, our proved reserves will decline materially as liquid hydrocarbons and natural gas are produced. Accordingly, to the extent we are not successful in replacing the liquid hydrocarbons and natural gas we produce, our future revenues will decline. Creating and maintaining an inventory of prospects for future production depends on many factors, including:

- obtaining rights to explore for, develop and produce liquid hydrocarbons and natural gas in promising areas;
- drilling success;
- the ability to complete long lead-time, capital-intensive projects timely and on budget;
- the ability to find or acquire additional proved reserves at acceptable costs; and
- the ability to fund such activity.

Future exploration and drilling results are uncertain and involve substantial costs.

Drilling for liquid hydrocarbons and natural gas involves numerous risks, including the risk that we may not encounter commercially productive liquid hydrocarbon and natural gas reservoirs. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts and surface cratering;
- lack of access to pipelines or other transportation methods; and
- shortages or delays in the availability of services or delivery of equipment.

If we are unable to complete capital projects at their expected costs and in a timely manner, or if the market conditions assumed in our project economics deteriorate, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Delays or cost increases related to capital spending programs involving engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays or cost increases may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;
- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project s debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our ongoing capital projects.

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We may incur substantial capital expenditures and operating costs as a result of compliance with, and changes in environmental health, safety and security laws and regulations, and, as a result, our business, financial condition, results of operation and cash flows could be materially and adversely affected.

Our businesses are subject to numerous laws, regulations and other requirements relating to the protection of the environment, including those relating to the discharge of materials into the environment such as the venting or flaring of natural gas, waste management, pollution prevention, greenhouse gas emissions, as well as laws and regulations relating to public and employee safety and health and to facility security. We have incurred and may continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products, our operating results will be adversely affected. The specific impact of these laws and regulations may vary depending on a number of factors, including the age and location of operating facilities and production processes. We may also be required to make material expenditures to modify operations, install pollution control equipment, perform site cleanups or curtail operations that could materially and adversely affect business, financial condition, results of operation and cash flows. We may become subject to liabilities that we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws or regulations could result in civil penalties or criminal fines and other enforcement actions against us.

We believe it is likely that the scientific and political attention to issues concerning the extent, causes of and responsibility for climate change will continue, with the potential for further regulations that could affect our operations. Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of review, discussion or implementation in countries where we operate, including the U.S., Canada, and Norway, and the European Union. Our operations result in these greenhouse gas emissions. Through 2011, domestic legislative and regulatory efforts included proposed federal legislation and state actions to develop statewide or regional programs, each of which could impose reductions in greenhouse gas emissions. Further, in December 2011 at the Durban Climate Change Conference, countries such as the U.S., China and India, and the European Union agreed in principal to replace the Kyoto Protocol (which expires in 2012) with a new legally binding agreement. However, at this time it is not certain whether a legally binding resolution will be reached, what the terms of any agreement would be, or whether the U.S. Senate would ratify such an agreement. These actions could result in increased: (1) costs to operate and maintain our facilities, (2) capital expenditures to install new emission controls at our facilities, and (3) costs to administer and manage any potential greenhouse gas emissions or carbon trading or tax programs. These costs and capital expenditures could be material. Although uncertain, these developments could increase our costs, reduce the demand for liquid hydrocarbons and natural gas, and create delays in our obtaining air pollution permits for new or modified facilities.

Although there may be adverse financial impact (including compliance costs, potential permitting delays and potential reduced demand for liquid hydrocarbons or natural gas) associated with any legislation, regulation, or other action by the U.S. EPA, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the fact that requirements have only recently been adopted and the present uncertainty regarding any additional measures and how they will be implemented. Private party litigation has also been brought against some emitters of greenhouse gas emissions.

The potential adoption of federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. The U.S. Congress has considered legislation that would require additional regulation affecting the hydraulic fracturing process. Consideration of new federal regulation and increased state oversight continues to arise. The U.S. EPA announced in the first quarter of 2010 its intention to conduct a comprehensive research study on the potential effects that hydraulic fracturing may have on water quality and public health. The U.S. EPA has begun preparation for the study and expects to issue an interim report in 2012 followed by a final report in 2014. In addition, various state-level initiatives in regions with substantial shale gas resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal or state laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs.

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Worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.

Local political and economic factors in global markets could have a material adverse effect on us. A total of 64 percent of our liquid hydrocarbon and natural gas sales volumes in 2011 was derived from production outside the U.S. and 64 percent of our proved liquid hydrocarbon and natural gas reserves as of December 31, 2011, were located outside the U.S. All of our synthetic crude oil production and proved reserves are located in Canada. We are, therefore, subject to the political, geographic and economic risks and possible terrorist activities attendant to doing business with suppliers located within or outside of the U.S. There are many risks associated with operations in countries and in global markets, such as Equatorial Guinea, Indonesia, Libya and the Iraqi Kurdistan Region, including:

- changes in governmental policies relating to liquid hydrocarbon, natural gas, bitumen or synthetic crude oil pricing and taxation;
- other political, economic or diplomatic developments and international monetary fluctuations;
- political and economic instability, war, acts of terrorism and civil disturbances;
- the possibility that a government may seize our property with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements or may impose additional taxes or royalty burdens; and
- fluctuating currency values, hard currency shortages and currency controls.

Since January 2010, there have been varying degrees of political instability and public protests, including demonstrations which have been marked by violence, within some countries in the Middle East including Bahrain, Egypt, Libya, Syria, Tunisia and Yemen. Some political regimes in these countries are threatened or have changed as a result of such unrest. If such unrest continues to spread, conflicts could result in civil wars, regional conflicts, and regime changes resulting in governments that are hostile to the U.S. These may have the following results, among others:

- volatility in global crude oil prices which could negatively impact the global economy, resulting in slower economic growth rates and reduced demand for our products;
- negative impact on the world crude oil supply if transportation avenues are disrupted;
- security concerns leading to the prolonged evacuation of our personnel;
- damage to, or the inability to access, production facilities or other operating assets; and
- inability of our service and equipment providers to deliver items necessary for us to conduct our operations.

Continued hostilities in the Middle East and the occurrence or threat of future terrorist attacks could adversely affect the economies of the U.S. and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. These risks could lead to increased volatility in prices for liquid hydrocarbons and natural gas. In addition, these risks could increase instability in the financial and insurance markets and make it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate.

Actions of governments through tax and other legislation, executive order and commercial restrictions could reduce our operating profitability, both in the U.S. and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries and will continue to do so in the future.

Many of our major projects and operations are conducted with partners, which may decrease our ability to manage risk.

We often enter into arrangements to conduct certain business operations, such oil and gas exploration and production, oil sands mining or pipeline transportation, with partners in order to share risks associated with those operations. However, these arrangements also may decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited influence over and control of the behaviors and performance of these operations. In addition, misconduct, fraud, noncompliance with applicable laws and regulations or improper activities by or on behalf of one or more of our partners could have a significant negative impact on our business and reputation.

Our operations are subject to business interruptions and casualty losses. We do not insure against all potential losses and therefore we could be seriously harmed by unexpected liabilities and increased costs.

Our exploration and production operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, spills, hurricanes and other adverse weather, tsunamis, earthquakes, volcanic eruptions or nuclear or other disasters, labor disputes and accidents. Our oil sands mining operations are subject to business interruptions due to breakdown or failure of equipment or processes and unplanned events such as fires, earthquakes, explosions or other interruptions. These same risks can be applied to the third-parties which transport crude oil from our facilities. A prolonged disruption in the ability of any pipeline or vessels to transport crude oil could contribute to a business interruption or increase costs.

Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. These hazards could result in serious personal injury or loss of human life, significant damage to property and equipment, environmental pollution, impairment of operations and substantial losses to us. Various hazards have adversely affected us in the past, and damages resulting from a catastrophic occurrence in the future involving us or any of our assets or operations may result in our being named as a defendant in one or more lawsuits asserting potentially large claims or in our being assessed potentially substantial fines by governmental authorities. We maintain insurance against many, but not all, potential losses or liabilities arising from operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Historically, we have maintained insurance coverage for physical damage and resulting business interruption to our major onshore and offshore facilities, with significant self-insured retentions. In the future, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, due to hurricane activity in recent years, the availability of insurance coverage for our offshore facilities for windstorms in the Gulf of Mexico region has been reduced or, in many instances, it is prohibitively expensive. As a result, our exposure to losses from future windstorm activity in the Gulf of Mexico region has increased.

Litigation by private plaintiffs or government officials could adversely affect our performance.

We currently are defending litigation and anticipate that we will be required to defend new litigation in the future. The subject matter of such litigation may include releases of hazardous substances from our facilities, privacy laws, antitrust laws or any other laws or regulations that apply to our operations. In some cases the plaintiff or plaintiffs seek alleged damages involving large classes of potential litigants, and may allege damages relating to extended periods of time or other alleged facts and circumstances. If we are not able to successfully defend such claims, they may result in substantial liability. We do not have insurance covering all of these potential liabilities. In addition to substantial liability, litigation may also seek injunctive relief which could have an adverse effect on our future operations.

In connection with our separation from MPC, MPC agreed to indemnify us for certain liabilities. However, there can be no assurance that the indemnity will be sufficient to protect us against the full amount of such liabilities, or that MPC s ability to satisfy its indemnification obligations will not be impaired in the future.

Pursuant to the separation and distribution agreement and the tax sharing agreement we entered into with MPC in connection with the spin-off, MPC agreed to indemnify us for certain liabilities. However, third parties could seek to hold us responsible for any of the liabilities that MPC agreed to retain or assume, and there can be no assurance that the indemnification from MPC will be sufficient to protect us against the full amount of such liabilities, or that MPC will be able to fully satisfy its indemnification obligations. In addition, even if we ultimately succeed in recovering from MPC any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves.

The spin-off could result in substantial tax liability.

We obtained a private letter ruling from the IRS substantially to the effect that the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections 355 and 368 and related provisions of the U.S. Internal Revenue Code of 1986, as amended (the Code). If the factual assumptions or representations made in the request for the private letter ruling prove to have been inaccurate or incomplete in any material respect, then we will not be able to rely on the ruling. Furthermore, the IRS does not rule on whether a distribution such as the spin-off satisfies certain requirements necessary to obtain tax-free treatment under Section 355 of the Code. Rather, the private letter ruling was based on representations by us that those requirements were satisfied, and any inaccuracy in those representations could invalidate the ruling. In connection with the spin-off, we also obtained an opinion of outside counsel, substantially to the effect that, the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections 355 and 368 and related provisions of the Code. The opinion relied on, among other things, the continuing validity of the private letter ruling and various assumptions and representations as to factual matters made by MPC and us which, if inaccurate or incomplete in any material respect, would jeopardize the conclusions reached by such counsel in its opinion. The opinion is not binding on the IRS or the courts, and there can be no assurance that the IRS or the courts would not challenge the conclusions stated in the opinion or that any such challenge would not prevail.

If, notwithstanding receipt of the private letter ruling and opinion of counsel, the spin-off were determined not to qualify under Section 355 of the Code, each U.S. holder of our common stock who received shares of MPC common stock in the spin-off would generally be treated as receiving a taxable distribution of property in an amount equal to the fair market value of the shares of MPC common stock received. That distribution would be taxable to each such stockholder as a dividend to the extent of our accumulated earnings and profits as of the effective date of the spin-off. For each such stockholder, any amount that exceeded those earnings and profits would be treated first as a non-taxable return of capital to the extent of such stockholder s tax basis in its shares of our common stock with any remaining amount being taxed as a capital gain. We would be subject to tax as if we had sold all the outstanding shares of MPC common stock in a taxable sale for their fair market value and would recognize taxable gain in an amount equal to the excess of the fair market value of such shares over our tax basis in such shares.

Under the terms of the tax sharing agreement we entered into with MPC in connection with the spin-off, MPC is generally responsible for any taxes imposed on MPC or us and our subsidiaries in the event that the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment as a result of actions taken, or breaches of representations and warranties made in the tax sharing agreement, by MPC or any of its affiliates. However, if the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment because of actions or failures to act by us or any of our affiliates, we would be responsible for all such taxes.

We may issue preferred stock whose terms could dilute the voting power or reduce the value of Marathon Oil common stock.

Our restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such preferences, powers and relative, participating, optional and other rights, including preferences over Marathon Oil common stock respecting dividends and distributions, as our Board of Directors generally may determine. The terms of one or more classes or series of preferred stock could dilute the voting power or reduce the value of Marathon Oil common stock. For example, we could grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we could assign to holders of preferred stock could affect the residual value of the common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and general character of our principal liquid hydrocarbon and natural gas properties, oil sands mining properties and facilities, and other important physical properties have been described by segment under Item 1. Business. Except for oil and gas producing properties, including oil sands mines, which generally are leased, or as otherwise stated, such properties are held in fee. The plants and facilities have been constructed or acquired over a period of years and vary in age and operating efficiency. At the date of acquisition of important properties, titles were examined and opinions of counsel obtained, but no title examination has been made specifically for the purpose of this document. The properties classified as owned in fee generally have been held for many years without any material unfavorably adjudicated claim.

Net liquid hydrocarbon, natural gas, and synthetic crude oil sales volumes are set forth in Item 8. Financial Statements and Supplementary Data Supplemental Statistics. Estimated net proved liquid hydrocarbon, natural gas and synthetic crude oil reserves are set forth in Item 8. Financial Statements and Supplementary Data Supplementary Information on Oil and Gas Producing Activities Estimated Quantities of Proved Oil and Gas Reserves. The basis for estimating these reserves is discussed in Item 1. Business Reserves.

Item 3. Legal Proceedings

We are defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

Litigation

In March 2011, Noble Drilling (U.S.) LLC (Noble) filed a lawsuit against us in the District Court of Harris County, Texas alleging, among other things, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation, relating to a multi-year drilling contract for a newly constructed drilling rig to be deployed in the U.S. Gulf of Mexico. We filed an answer in April 2011, contending, among other things, failure to perform, failure to comply

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with material obligations, failure to mitigate alleged damages and that Noble failed to provide the rig according to the operating, performance and safety requirements specified in the drilling contract. Noble is seeking an unspecified amount of damages. We are vigorously defending this litigation. The ultimate outcome of this lawsuit, including any financial effect on us, remains uncertain. We do not believe an estimate of a reasonably probable loss (or range of loss) can be made for this lawsuit at this time.

Environmental Proceedings

The following is a summary of proceedings involving us that were pending or contemplated as of December 31, 2011, under federal and state environmental laws. Except as described herein, it is not possible to predict accurately the ultimate outcome of these matters; however, management s belief set forth in the first paragraph under Legal Proceedings above takes such matters into account.

Claims under CERCLA and related state acts have been raised with respect to the clean-up of various waste disposal and other sites. CERCLA is intended to facilitate the clean-up of hazardous substances without regard to fault. Potentially responsible parties (PRP) for each site include present and former owners and operators of, transporters to and generators of the substances at the site. We had been identified as a PRP at five CERCLA waste sites, however, after the June 30, 2011 spin-off of our downstream business, MPC has indemnified Marathon and retained liability for all of these sites.

As of December 31, 2011, we have identified 20 sites where remediation is being sought under other environmental statutes, both federal and state, or where private parties are seeking remediation through discussions or litigation. Based on currently available information, which is in many cases preliminary and incomplete, we believe that liability for clean-up and remediation costs in connection with these sites will be less than $25 million.

We have been working with the North Dakota Department of Health to resolve voluntary disclosures we made in 2009 relating to potential Clean Air Act violations relating to our operations on state lands in the Bakken shale. The amount of the potential fine is estimated to be $100,000.

The projected liability for clean-up and remediation provided in the preceding paragraph is a forward-looking statement. To the extent that our assumptions prove to be inaccurate, future expenditures may differ materially from those stated in the forward-looking statement.

SEC Investigation Relating to Libya

On May 25, 2011, we received a subpoena issued by the SEC requiring production of documents related to payments made to the government of Libya, or to officials and persons affiliated with officials of the government of Libya. We have been and intend to continue cooperating with the SEC in its investigation.

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PART II

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

The principal market on which Marathon Oil common stock is traded is the New York Stock Exchange (NYSE). As of January 31, 2012, there were 46,783 registered holders of Marathon Oil common stock.

The following table reflects high and low sales prices for Marathon Oil common stock and the related dividend per share by quarter for the past two years:

	2011*			2010		
Dollars per share	High Price	Low Price	Dividends	High Price	Low Price	Dividends
Quarter 1	$ 53.31	$ 37.34	$ 0.25	$ 32.85	$ 28.04	$ 0.24
Quarter 2	54.17	49.06	0.25	34.11	30.19	0.25
Quarter 3	34.07	21.58	0.15	34.98	30.21	0.25
Quarter 4	29.34	20.27	0.15	37.03	33.07	0.25
Full Year	$ 54.17	$ 20.27	$ 0.80	$ 37.03	$ 28.04	$ 0.99

* On June 30, 2011, we completed the spin-off our downstream business. The June 30, 2011 closing price of our common stock on the NYSE was $52.68. On July 1, 2011, the opening price of our common stock on the NYSE was $32.95. Our quarterly dividend was also adjusted to $0.15 per share.

Dividends

Our Board of Directors intends to declare and pay dividends on Marathon Oil common stock based on the financial condition and results of operations of Marathon Oil Corporation, although it has no obligation under Delaware law or the Restated Certificate of Incorporation to do so. In determining the dividend policy with respect to Marathon Oil common stock, the Board will rely on the consolidated financial statements of Marathon Oil. Dividends on Marathon Oil common stock are limited to our legally available funds.

On January 27, 2012, we announced a 13 percent increase in our quarterly dividend to $0.17 per share.

Issuer Purchases of Equity Securities

The following table provides information about purchases by Marathon Oil and its affiliated purchaser during the quarter ended December 31, 2011, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934:

Period	Column (a) Total Number of Shares Purchased[(a)]	Column (b) Average Price Paid per Share	Column (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(c)]	Column (d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(c)]
10/01/11 10/31/11	6,217	$ 20.84	-	$ 1,780,609,536
11/01/11 11/30/11	12,748	$ 25.03	-	$ 1,780,609,536
12/01/11 12/31/11	40,420[(b)]	$ 27.21	-	$ 1,780,609,536
Total	59,385	$ 26.08	-	

(a) 26,396 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) 32,989 shares were repurchased in open-market transactions to satisfy the requirements for dividend reinvestment under the Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the Dividend Reinvestment Plan) by the administrator of the Dividend Reinvestment Plan. Shares needed to meet the requirements of the Dividend Reinvestment Plan are either purchased in the open market or issued directly by Marathon Oil.

(c) We announced a share repurchase program in January 2006, and amended it several times in 2007 for a total authorized program of $5 billion. As of December 31, 2011, 78 million common shares had been acquired at a cost of $3,222 million, which includes transaction fees and commissions that are not reported in the table above. Of this total, 66 million shares had been acquired at a cost of $2,922 million prior the spin-off of the downstream business (see Item 8. Financial Statements and Supplementary Data Note 3 to the consolidated financial statements).

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Item 6. Selected Financial Data

(Dollars in millions, except as noted)	2011[b]	2010[c]	2009[d]	2008[d][e]	2007[d][f][g]
Statement of Income Data[a]					
Revenues	$ 14,663	$ 11,690	$ 8,524	$ 13,162	$ 8,569
Income from continuing operations	1,707	1,882	716	2,192	1,699
Net income	2,946	2,568	1,463	3,528	3,956
Per Share Data					
Basic :					
Income from continuing operations	$ 2.40	$ 2.65	$ 1.01	$ 3.09	$ 2.46
Net income	$ 4.15	$ 3.62	$ 2.06	$ 4.97	$ 5.73
Diluted :					
Income from continuing operations	$ 2.39	$ 2.65	$ 1.01	$ 3.08	$ 2.44
Net income	$ 4.13	$ 3.61	$ 2.06	$ 4.95	$ 5.69
Statement of Cash Flows Data[a]					
Additions to property, plant and equipment related to continuing operations	$ 3,295	$ 3,536	$ 3,349	$ 4,202	$ 2,354
Dividends paid	567	704	679	681	637
Dividends per share	$ 0.80	$ 0.99	$ 0.96	$ 0.96	$ 0.92
Balance Sheet Data as of December 31:					
Total assets	$ 31,371	$ 50,014	$ 47,052	$ 42,686	$ 42,746
Total long-term debt, including capitalized leases	4,674	7,601	8,436	7,087	6,084

(a) Our downstream business was spun-off on June 30, 2011. Previous periods have been recast to reflect the business in discontinued operations (see Item 8. Financial Statements and Supplementary Data Note 3 to the consolidated financial statements).

(b) Includes impairments of $310 million primarily related to E&P segment assets (see Item 8. Financial Statements and Supplementary Data Note 15 to the consolidated financial statements).

(c) Includes impairments of $447 million primarily related to E&P segment assets (see Item 8. Financial Statements and Supplementary Data Note 15 to the consolidated financial statements).

(d) Our businesses in Ireland and Gabon were sold in 2009. Previous periods have been recast to reflect these businesses in discontinued operations.

(e) Includes a $1,412 million impairment of goodwill related to the OSM reporting unit.

(f) On October 18, 2007, we completed the acquisition of all the outstanding shares of Western Oil Sands Inc.

(g) Effective May 1, 2007, we no longer consolidate EGHoldings and our investment in EGHoldings is accounted for under the equity method of accounting; therefore, EGHoldings additions to property, plant and equipment subsequent to April 2007 are not included in our additions to property, plant and equipment related to continuing operations.

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

We are an international energy company with operations in the U.S., Canada, Africa, the Middle East and Europe. Our operations are organized into three reportable segments:

- E&P which explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.

- OSM which mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

- IG which produces and markets products manufactured from natural gas, such as LNG and methanol, in EG.

Certain sections of Management s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as anticipates, believes, estimates, expects, targets, plans, projects, could, may, should, would or similar words indicating that future outcomes are uncertain. In acc safe harbor provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors in this Annual Report on Form 10-K.

Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information under Item 1. Business, Item 1A. Risk Factors and Item 8. Financial Statements and Supplementary Data found in this Annual Report on Form 10-K.

Spin-off Downstream Business

On June 30, 2011, the spin-off of Marathon s downstream business was completed, creating two independent energy companies: Marathon Oil and MPC. Marathon shareholders at the close of business on the record date of June 27, 2011 received one share of MPC common stock for every two shares of Marathon common stock held. Fractional shares of MPC common stock were not distributed and any fractional share of MPC common stock otherwise issuable to a Marathon shareholder was sold in the open market on such shareholder s behalf, and such shareholder received a cash payment with respect to that fractional share. A private letter tax ruling received in June 2011 from the IRS affirmed the tax-free nature of the spin-off. Activities related to the downstream business have been treated as discontinued operations in all periods presented in this Annual Report on Form 10-K (see Item 8. Financial Statements and Supplementary Data Note 3 to the consolidated financial statements for additional information).

Overview Market Conditions

Exploration and Production

Prevailing prices for the various grades of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Prices of crude oil have been volatile in recent years. In 2011, crude prices increased over 2010 levels, with increases in Brent averages outstripping those in WTI. During much of 2010, both WTI and Brent crude oil monthly average prices remained in the $75 to $85 per barrel range. Crude oil prices reached a low of $33.98 in February 2009, following global demand declines in an economic recession, but recovered quickly ending 2009 at $79.36. The following table lists benchmark crude oil and natural gas price annual averages for the past three years.

Benchmark	2011	2010	2009
WTI crude oil *(Dollars per bbl)*	$ 95.11	$ 79.61	$ 62.09
Brent (Europe) crude oil *(Dollars per bbl)*	111.26	79.51	61.49
Henry Hub natural gas *(Dollars per mmbtu)*[(a)]	$ 4.04	$ 4.39	$ 3.99

(a) Settlement date average.

Our U.S. crude oil production was approximately 58 percent sour in 2011 and 68 percent in 2010. Sour crude contains more sulfur than light sweet WTI does. Sour crude oil also tends to be heavier than light sweet crude oil and sells at a discount to light sweet crude oil because of higher refining costs and lower refined product values. Our international crude oil production is relatively sweet and is generally sold in relation to the Brent crude benchmark. The differential between WTI and Brent average prices widened significantly in 2011 to $16.15 in comparison to differentials of less than $1.00 in 2010 and 2009.

A significant portion of our natural gas production in the lower 48 states of the U.S. is sold at bid-week prices or first-of-month indices relative to our specific producing areas. Average settlement date Henry Hub natural gas prices have been relatively stable for the periods of this report; however, a decline began in September 2011 which has continued in 2012 with February averaging $2.68 per mmbtu. Should U.S. natural gas prices remain depressed, an impairment charge related to our natural gas assets may be necessary.

Our other major natural gas-producing regions are Europe and EG. Natural gas prices in Europe have been significantly higher than in the U.S. In the case of EG our natural gas sales are subject to term contracts, making realized prices less volatile. The natural gas sales from EG are at fixed prices; therefore, our worldwide reported average natural gas realized prices may not fully track market price movements.

Oil Sands Mining

OSM segment revenues correlate with prevailing market prices for the various qualities of synthetic crude oil we produce. Roughly two-thirds of the normal output mix will track movements in WTI and one-third will track movements in the Canadian heavy sour crude oil marker, primarily Western Canadian Select. Output mix can be impacted by operational problems or planned unit outages at the mines or the upgrader.

The operating cost structure of the oil sands mining operations is predominantly fixed and therefore many of the costs incurred in times of full operation continue during production downtime. Per-unit costs are sensitive to production rates. Key variable costs are natural gas and diesel fuel, which track commodity markets such as the Canadian Alberta Energy Company (AECO) natural gas sales index and crude oil prices, respectively. Recently AECO prices have declined, much as Henry Hub prices have. We would expect a significant, continued declined in natural gas prices to have a favorable impact on OSM operating costs.

The table below shows average benchmark prices that impact both our revenues and variable costs.

Benchmark	2011	2010	2009
WTI crude oil *(Dollars per bbl)*	$ 95.11	$ 79.61	$ 62.09
Western Canadian Select *(Dollars per bbl)*[(a)]	77.97	65.31	52.13
AECO natural gas sales index *(Dollars per mmbtu)*[(b)]	$ 3.68	$ 3.89	$ 3.49

(a) Monthly pricing based upon average WTI adjusted for differentials unique to western Canada.

(b) Monthly average day ahead index.

Integrated Gas

Our integrated gas operations include production and marketing of products manufactured from natural gas, such as LNG and methanol, in EG.

World LNG trade in 2011 has been estimated to be 241 mmt. Long-term, LNG continues to be in demand as markets seek the benefits of clean burning natural gas. Market prices for LNG are not reported or posted. In general, LNG delivered to the U.S. is tied to Henry Hub prices and will track with changes in U.S. natural gas prices, while LNG sold in Europe and Asia is indexed to crude oil prices and will track the movement of those prices. We have a 60 percent ownership in an LNG production facility in Equatorial Guinea, which sells LNG under a long-term contract at prices tied to Henry Hub natural gas prices. Gross sales from the plant were 4.1 mmt, 3.7 mmt and 3.9 mmt in 2011, 2010 and 2009.

We own a 45 percent interest in a methanol plant located in Equatorial Guinea through our investment in AMPCO. Gross sales of methanol from the plant totaled 1,039,657, 850,605 and 960,374 metric tonnes in 2011, 2010 and 2009. Methanol demand has a direct impact on AMPCO s earnings. Because global demand for methanol is rather limited, changes in the supply-demand balance can have a significant impact on sales prices. World demand for methanol in 2011 has been estimated to be 55.4 mmt. Our plant capacity of 1.1 mmt is about 2 percent of total demand.

Operating and Financial Highlights

Significant operating and financial highlights during 2011 include:

Completed the spin-off of our downstream business on June 30, 2011

Acquired a significant operated position in the Eagle Ford shale play in south Texas

Added net proved reserves, for the E&P and OSM segments combined, of 307 mmboe, excluding dispositions, for a 212 percent reserve replacement ratio

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Increased proved liquid hydrocarbon, including synthetic crude oil, reserves to 78 percent from 75 percent of proved reserves

Increased E&P net sales volumes, excluding Libya, by 7 percent

Recorded 96 percent average operational availability for all major company-operated E&P assets, compared to 94 percent in 2010

Completed debottlenecking work that increased crude oil production capacity at the Alvheim FPSO in Norway to 150,000 gross bbld from the previous capacity of 142,000 gross bbld and the original 2008 capacity of 120,000 gross bbld

Announced two non-operated discoveries in the Iraqi Kurdistan Region and began drilling in Poland

Completed AOSP Expansion 1, including the start-up of the expanded Scotford upgrader, realizing an increase in net synthetic crude oil sales volumes of 48 percent

Completed dispositions of non-core assets and interests in acreage positions for net proceeds of $518 million

Repurchased 12 million shares of our common stock at a cost of $300 million

Retired $2,498 million principal of our long-term debt

Resumed limited production in Libya in the fourth quarter of 2011 following the February 2011 temporary suspension of operations

Consolidated Results of Operations: 2011 compared to 2010

Due to the spin-off of our downstream business on June 30, 2011, which is reported as discontinued operations, income from continuing operations is more representative of Marathon Oil as an independent energy company. Consolidated income from continuing operations before income taxes was 9 percent higher in 2011 than in 2010, largely due to higher liquid hydrocarbon prices. This improvement was offset by increased income taxes primarily the result of excess foreign tax credits generated during 2011 that we do not expect to utilize in the future. The effective income tax rate for continuing operations was 61 percent in 2011 compared to 54 percent in 2010.

Revenues are summarized in the following table:

(In millions)	2011	2010
E&P	$ 13,029	$ 10,782
OSM	1,588	833
IG	93	150
Segment revenues	14,710	11,765
Elimination of intersegment revenues	(47)	(75)
Total revenues	$ 14,663	$ 11,690

E&P segment revenues increased $2,247 million from 2010 to 2011, primarily due to higher average liquid hydrocarbon realizations, which were $99.37 per bbl in 2011, a 31 percent increase over 2010. Revenues in 2010 included net pre-tax gains of $95 million on derivative instruments intended to mitigate price risk on future sales of liquid hydrocarbons and natural gas.

Included in our E&P segment are supply optimization activities which include the purchase of commodities from third parties for resale. Supply optimization serves to aggregate volumes in order to satisfy transportation commitments and to achieve flexibility within product types and delivery points. See the Cost of revenues discussion as revenues from supply optimization approximate the related costs. Higher average crude oil prices in 2011 compared to 2010 increased revenues related to supply optimization.

Revenues from the sale of our U.S. production are higher in 2011 primarily as a result of higher liquid hydrocarbon and natural gas price realizations, but sales volumes declined.

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The following table gives details of net sales and average realizations of our U.S. operations.

	2011	2010
United States Operating Statistics		
Net liquid hydrocarbon sales *(mbbld)*[(a)]	75	70
Liquid hydrocarbon average realizations *(per bbl)*[(b)]	$ 92.55	$ 72.30
Net natural gas sales *(mmcfd)*	326	364
Natural gas average realizations *(per mcf)*[(b)]	$ 4.95	$ 4.71

(a) Includes crude oil, condensate and natural gas liquids.

(b) Excludes gains and losses on derivative instruments.

Increased liquid hydrocarbon sales volumes in 2011 were a result of new wells in the Bakken shale, new production from acreage acquired in the Eagle Ford shale and increased production from the Droshky development in the Gulf of Mexico, which commenced operations in July 2010. Natural gas sales volumes were lower in 2011 as compared to 2010 due to the sale of a portion of our Powder River Basin asset in 2010, decreased demand in Alaska and natural field declines, partly offset by increased natural gas production from the Droshky development.

The following table gives details of net sales and average realizations of our international operations.

	2011	2010
International Operating Statistics		
Net liquid hydrocarbon sales *(mbbld)*[(a)]		
Europe	101	92
Africa	43	83
Total International	144	175
Liquid hydrocarbon average realizations *(per bbl)*[(b)]		
Europe	$ 115.55	$ 81.95
Africa	73.21	71.71
Total International	$ 102.96	$ 77.11
Net natural gas sales *(mmcfd)*		
Europe[(c)]	97	105
Africa	443	409
Total International	540	514
Natural gas average realizations *(per mcf)*[(b)]		
Europe	$ 9.84	$ 7.10
Africa	0.24	0.25
Total International	$ 1.97	$ 1.65

(a) Includes crude oil, condensate and natural gas liquids. The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Excludes gains and losses on derivative instruments.

(c) Includes natural gas acquired for injection and subsequent resale of 16 mmcfd and 18 mmcfd in 2011 and 2010.

Compared to 2010, international liquid hydrocarbon sales volumes are lower due to the temporary cessation of production from Libya in February 2011. In the fourth quarter of 2011, limited production resumed from the Waha concessions, but we made no deliveries of hydrocarbons. Sales are planned to resume in the first quarter of 2012. Partially offsetting the impact of Libya, were higher liquid hydrocarbon sales from Norway due to increasing capacity of the Alvheim FPSO and from two new West Brae wells in the U.K. Natural gas sales volumes from EG were higher in 2011 due to a turnaround in 2010, while natural gas sales volumes from Europe were down primarily related to 2011 planned turnarounds and normal production declines in the U.K.

OSM segment revenues increased $755 million from 2010 to 2011. Revenues were impacted by net pre-tax gains of $25 million on derivative instruments in 2010. The increase in revenue is due to higher synthetic crude oil sales volumes and realizations as shown on the table below.

	2011	2010
OSM Operating Statistics		
Net synthetic crude oil sales *(mbbld)*[(a)]	43	29
Synthetic crude average realizations *(per bbl)*	$ 91.65	$ 71.06

(a) Includes blendstocks.

The 2011 sales volumes improved as a result of the Jackpine mine, which commenced operations in late 2010, and the upgrader expansion which was completed and commenced operations in the second quarter of 2011. Sales volumes in 2010 were impacted by a turnaround that commenced in late March 2010 that caused production to be completely shut down in April, with a staged resumption in May 2010.

IG segment revenues decreased $57 million in 2011 from 2010 because sales of LNG from our Alaska operations declined throughout 2011 as we planned to shut down the LNG facility. In the third quarter of 2011, sales from the LNG facility ceased completely because we sold our equity interest in the facility.

Income from equity method investments increased $118 million in 2011 from 2010 primarily due to the impact of higher liquid hydrocarbon prices on the earnings of certain of our equity method investees in 2011.

Net gain on disposal of assets in 2011 is primarily related to sales of non-core assets, such as the Burns Point gas plant and the Alaska LNG facility, and the assignment of interests in our DJ Basin and Poland acreage positions. The 2010 gain is primarily related to the pretax gain of $811 million on the sale of a 20 percent outside-operated interest in our Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. See Item 8. Financial Statements and Supplementary Data Note 6 to the consolidated financial statements for discussion of significant dispositions.

Cost of revenues increased $1,439 million from 2010 to 2011 primarily due to the impact of higher crude oil prices on our supply optimization activities. Costs related to supply optimization were $3,599 million in 2011 compared to $2,530 million in 2010.

Additionally, total OSM segment costs increased for 2011 primarily because the Jackpine mine commenced production in late 2010 and the upgrader expansion came online in 2011. Although gross costs are up due to the increased volumes from the expansion, per barrel costs have been declining in comparison with 2010. OSM segment costs also increased in 2011 when compared to 2010 due to the expansion s operation start-up costs. These increases were partially offset by no turnaround costs in 2011. We incurred $99 million in 2010 associated with the turnaround. Additionally, estimated net costs of $64 million were recorded in 2011 to address water flow in a previously mined and contained area of the Muskeg River mine.

Purchases from related parties increased $78 million from 2010 as a result of purchases from the Alba LPG plant in EG, in which we own an equity interest. Higher liquid hydrocarbon prices in 2011 increased the value of those purchases.

Depreciation, depletion and amortization increased $210 million in 2011 from 2010. Since both our E&P and OSM segments apply the units-of-production method to the majority of their assets, the previously discussed increases or decreases in sales volumes generally result in similar changes in DD&A. Increased DD&A expense in 2011 reflects the impact of higher OSM segment sales volumes, partially offset by decreases in E&P segment sales volumes. The DD&A rate (expense per barrel of oil equivalent), which is impacted by changes in proved reserves and capitalized costs, can also cause changes in our DD&A. The following table provides DD&A rates for our E&P and OSM segments.

($ per boe)	2011	2010
DD&A rate		
E&P Segment		
United States	$ 25	$ 22
International	10	9
OSM Segment	$ 18	$ 16

Impairments in 2011 related primarily to our Droshky development in the Gulf of Mexico for $273 million and an intangible asset for an LNG delivery contract at Elba Island. Impairments in 2010 include $423 million related to our Powder River Basin field in the first quarter, as well as smaller impairments to other E&P segment fields due to reductions in estimated reserves, reduced drilling expectations and declining natural gas prices. See Item 8. Financial Statements and Supplementary Data Note 15 to the consolidated financial statements for further information about the impairments.

General and administrative expenses increased $53 million in 2011 compared to 2010 primarily due to additional compensation expense related to performance units and stock based compensation expense.

Other taxes increased $31 million in 2011 compared to 2010. With the increase in revenues, particularly related to higher prices, production and ad valorem taxes increased.

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Exploration expenses were higher in 2011 than 2010 primarily due to higher dry well costs. Dry wells primarily related to Indonesia, the Gulf of Mexico, Norway and various U.S. onshore properties in both 2011 and 2010. In addition, costs related to some suspended exploratory wells in Equatorial Guinea were expensed in 2010. Geologic and seismic costs have increased in 2011 over 2010 primarily related to the U.S. shale plays, Poland and the Iraqi Kurdistan Region.

The following table summarizes components of exploration expenses:

(In millions)	2011	2010
Dry well and unproved property impairment	$ 357	$ 223
Geological, geophysical, seismic	120	116
Other	167	159
Total exploration expenses	$ 644	$ 498

Loss on early extinguishment of debt relates to debt retirements in February and March of 2011 and in April of 2010. See Item 8. Financial Statements and Supplementary Data Note 17 to the consolidated financial statements for additional discussion of these transactions.

Provision for income taxes increased $545 million from 2010 to 2011 in part due to the increase in pretax income. In 2011, we increased the valuation allowance against foreign tax credits because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in 2011. A higher price and production outlook over the next several years for Norway due to better than expected performance contributed to generating these excess foreign tax credits. The following is an analysis of the effective income tax rates for 2011 and 2010:

	2011	2010
Statutory rate applied to income from continuing operations before income taxes	35%	35%
Effects of foreign operations, including foreign tax credits	6	20
Change in permanent reinvestment assertion	5	-
Adjustments to valuation allowances	14	(2)
Tax law changes	1	1
Effective income tax rate on continuing operations	61%	54%

The effective tax rate is influenced by a variety of factors including the geographical and functional sources of income, the relative magnitude of these sources of income, foreign currency remeasurement effects, and tax legislation changes. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in Corporate and other unallocated items shown in Item 8. Financial Statements and Supplementary Data Note 8 to the consolidated financial statements.

Effects of foreign operations The effects of foreign operations on our effective tax rate decreased in 2011 as compared to 2010, primarily due to the suspension of all production operations in Libya in the first quarter of 2011, where the statutory tax rate is in excess of 90 percent.

Change in permanent reinvestment assertion In the second quarter of 2011, we recorded $716 million of deferred U.S. tax on undistributed earnings of $2,046 million that we previously intended to permanently reinvest in foreign operations. Offsetting this tax expense were associated foreign tax credits of $488 million. In addition, we reduced our valuation allowance related to foreign tax credits by $228 million due to recognized deferred U.S. tax on previously undistributed earnings.

Adjustments to valuation allowance In 2011, we increased the valuation allowance against foreign tax credits because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in 2011.

See Item 8. Financial Statements and Supplementary Data Note 10 to the consolidated financial statements for further information about income taxes.

Discontinued operations reflect the June 30, 2011 spin-off of our downstream business and the historical results of those operations, net of tax, for all periods presented. See Item 8. Financial Statements and Supplementary Data Note 3 to the consolidated financial statements.

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Segment Results: 2011 compared to 2010

Segment income for 2011 and 2010 is summarized and reconciled to net income in the following table.

(In millions)	2011	2010
E&P		
United States	$ 366	$ 251
International	1,791	1,690
E&P segment	2,157	1,941
OSM	256	(50)
IG	178	142
Segment income	2,591	2,033
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(326)	(202)
Foreign currency remeasurement of taxes	9	32
Impairments	(195)	(286)
Loss on early extinguishment of debt	(176)	(57)
Tax effect of subsidiary restructuring	(122)	-
Deferred income taxes	(61)	(45)
Water abatement Oil Sands	(48)	-
Eagle Ford transaction costs	(10)	-
Gain on dispositions	45	407
Income from continuing operations	1,707	1,882
Discontinued operations	1,239	686
Net income	$ 2,946	$ 2,568

United States E&P income increased $115 million from 2010 to 2011. The majority of the income increase was due to higher liquid hydrocarbon realizations in 2011, along with higher liquid hydrocarbon sales volumes, partially offset by higher DD&A in the Gulf of Mexico and increased exploration and operating costs.

International E&P income increased $101 million from 2010 to 2011. This increase was primarily related to higher liquid hydrocarbon realizations, partially offset by lower liquid hydrocarbon sales volumes and higher income taxes.

OSM segment income increased $306 million from 2010 to 2011. The increase in segment income was primarily the result of higher synthetic crude oil sales volumes and higher price realizations.

IG segment income increased $36 million from 2010 to 2011. The increase in income was primarily the result of higher LNG and methanol sales volumes, somewhat offset by lower Henry Hub gas prices.

Consolidated Results of Operations: 2010 compared to 2009

Revenues are summarized in the following table:

(In millions)	2010	2009
E&P	$ 10,782	$ 7,738
OSM	833	692
IG	150	50

Segment revenues	11,765	8,480
Elimination of intersegment revenues	(75)	(28)
Gain on U.K. natural gas contracts	-	72
Total revenues	$ 11,690	$ 8,524

E&P segment revenues increased $3,044 million from 2009 to 2010, primarily due to higher average liquid hydrocarbon and natural gas realizations, slightly offset by lower natural gas sales volumes. On average, our worldwide liquid hydrocarbon realizations were 30 percent higher in 2010 than in 2009 and our worldwide natural gas realizations were 18 percent higher.

E&P segment revenues included net derivative gains of $95 million and losses of $13 million in 2010 and 2009. Excluded from E&P segment revenues were gains of $72 million in 2009 related to natural gas sales contracts in the U.K. that were accounted for as derivative instruments. These U.K. contracts expired in September 2009.

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Included in our E&P segment are supply optimization activities which include the purchase of commodities from third parties for resale. Supply optimization serves to aggregate volumes in order to satisfy transportation commitments and to achieve flexibility within product types and delivery points. See the Cost of revenues discussion as revenues from supply optimization are approximately equal to those costs. Higher average crude oil prices in 2010 compared to 2009 increased revenues related to supply optimization.

The following table gives details of net sales and average realizations of our U.S. operations.

	2010	2009
United States Operating Statistics		
Net liquid hydrocarbon sales *(mbbld)*[a]	70	64
Liquid hydrocarbon average realizations *(per bbl)*[b]	$ 72.30	$ 54.67
Net natural gas sales *(mmcfd)*	364	373
Natural gas average realizations *(per mcf)*[b]	$ 4.71	$ 4.14

(a) Includes crude oil, condensate and natural gas liquids.

(b) Excludes gains and losses on derivative instruments.

Liquid hydrocarbon sales volumes in 2010 benefited from the Droshky development in the Gulf of Mexico, which commenced production mid-year 2010.

The following table gives details of net sales and average realizations of our international operations.

	2010	2009
International Operating Statistics		
Net liquid hydrocarbon sales *(mbbld)*[a]		
Europe	92	92
Africa	83	87
Total International	175	179
Liquid hydrocarbon average realizations *(per bbl)*[b]		
Europe	$ 81.95	$ 64.46
Africa	71.71	53.91
Total International	$ 77.11	$ 59.31
Net natural gas sales *(mmcfd)*		
Europe[c]	105	138
Africa	409	430
Total International	514	568
Natural gas average realizations *(per mcf)*[b]		
Europe	$ 7.10	$ 4.90
Africa	0.25	0.25
Total International	$ 1.65	$ 1.38

(a) Includes crude oil, condensate and natural gas liquids. The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Excludes gains and losses on derivative instruments and the unrealized effects of U.K. natural gas contracts that were accounted for as derivatives.

(c) Includes natural gas acquired for injection and subsequent resale of 18 mmcfd and 22 mmcfd in 2010 and 2009.

Compared to 2009, international natural gas sales volumes are lower primarily due to a turnarounds in 2010 in EG and the U.K.

OSM segment revenues increased $141 million from 2009 to 2010. Revenues were impacted by net gains of $25 million and $13 million on derivative instruments in 2010 and 2009. Excluding the derivatives impact, the increase in revenue reflects the 26 percent increase in synthetic crude oil realizations. Synthetic crude oil sales volumes were lower in 2010 due to the impact of the planned turnaround at the Muskeg River mine and upgrader that began in late March 2010 and halted production in April before a staged resumption of operations in May 2010.

	2010	2009
OSM Operating Statistics		
Net synthetic crude oil sales *(mbbld)*[(a)]	29	32
Synthetic crude average realizations *(per bbl)*	$ 71.06	$ 56.44

(a) Includes blendstocks.

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IG segment revenues increased $100 million from 2009 to 2010 primarily due to higher commodity prices.

Income from equity method investments increased $76 million in 2010 from 2009 primarily due to the impact of higher commodity prices on the earnings of many of our equity method investees in 2010.

Net gain on disposal of assets in 2010 is primarily related to the pretax gain of $811 million on the sale of a 20 percent outside-operated interest in our Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. In 2009, we sold our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas, plus sales of other oil and gas properties.

Cost of revenues increased $1,616 million from 2009 to 2010 primarily due the impact of higher crude oil prices on our supply optimization activities. Costs related to supply optimization were $2,530 million in 2010 compared to $1,445 million in 2009. Additionally, OSM segment costs were higher in 2010 due to the planned turnaround at the Muskeg River mine and the upgrader.

Purchases from related parties increased $26 million from 2009 as a result of purchases from the Alba LPG plant in EG, in which we own an equity interest. Higher liquid hydrocarbon prices in 2010 increased the value of those purchases.

Depreciation, depletion and amortization increased $122 million in 2010 from 2009. Since both our E&P and OSM segments apply the units-of-production method to the majority of their assets, the previously discussed increases or decreases in sales volumes generally result in similar changes in DD&A. Increased DD&A in 2010 reflects the impact of higher sales volumes at a higher rate of DD&A per barrel on our U.S. E&P assets. The DD&A rate (expense per barrel of oil equivalent), which is impacted by changes in proved reserves and capitalized costs, can also cause changes in our DD&A. The following table provides DD&A rates for our E&P and OSM segments.

($ per boe)	2010	2009
DD&A rate		
E&P Segment		
United States	$ 22	$ 18
International	9	9
OSM Segment	$ 16	$ 12

Impairments in 2010 includes $423 million related to our Powder River Basin field in the first quarter, as well as smaller impairments to other E&P segment fields due to reductions in estimated reserves, reduced drilling expectations and declining natural gas prices. See Item 8. Financial Statements and Supplementary Data Note 15 to the consolidated financial statements for further information about the impairments.

General and administrative expenses increased $40 million in 2010 compared to 2009 primarily due to additional compensation expense and higher defined benefit costs (see Item 8. Financial Statements and Supplementary Data Note 20 to the consolidated financial statements for further information about defined benefit costs).

Other taxes increased $26 million in 2010 compared to 2009. With the increase in revenues, particularly related to higher prices, production and ad valorem taxes increased.

Exploration expenses were higher in 2010 than 2009 primarily due to higher dry well costs. Dry wells primarily related to Gulf of Mexico, Indonesia, Norway and various U.S. onshore properties in 2010 and to Europe and Africa in 2009. The following table summarizes the components of exploration expenses.

(In millions)	2010	2009
Dry well and unproved property impairment	$ 223	$ 83
Geological, geophysical, seismic	116	105

Other	159	119
Total exploration expenses	$ 498	$ 307

Loss on early extinguishment of debt relates to debt retirements in April of 2010. See Item 8. Financial Statements and Supplementary Data Note 17 to the consolidated financial statements for additional discussion of these transactions.

Provision for income taxes increased $128 million from 2009 to 2010 primarily due to the increase in pretax income. The effective rate, however, decreased from 74 percent in 2009 to 54 percent in 2010. In 2009 more income was generated in high tax jurisdictions than in 2010. In addition, in 2009, it was determined that we may not be able to realize all recorded foreign tax benefits and therefore a valuation allowance was recorded against these benefits.

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The following is an analysis of the effective income tax rates for 2010 and 2009:

	2010	2009
Statutory rate applied to income from continuing operations before income taxes	35%	35%
Effects of foreign operations, including foreign tax credits	20	16
Foreign currency remeasurement loss	-	11
Adjustments to valuation allowances	(2)	10
Tax law change	1	-
Other	-	2
Effective income tax rate on continuing operations	54%	74%

The effective tax rate is influenced by a variety of factors including the geographical and functional sources of income, the relative magnitude of these sources of income, foreign currency remeasurement effects, and tax legislation changes. See Item 8. Financial Statements and Supplementary Data Note 10 to the consolidated financial statements for further information about income taxes.

Discontinued operations reflect the June 30, 2011 spin-off of our downstream business and the 2009 disposals of our E&P businesses in Ireland and Gabon and their historical operating results, net of tax, for all periods presented. See Item 8. Financial Statements and Supplementary Data Notes 3 and 6 to the consolidated financial statements.

Segment Results: 2010 compared to 2009

Segment income for 2010 and 2009 is summarized and reconciled to net income in the following table.

(In millions)	2010	2009
E&P		
United States	$ 251	$ 52
International	1,690	1,166
E&P segment	1,941	1,218
OSM	(50)	44
IG	142	90
Segment income	2,033	1,352
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(202)	(431)
Foreign currency remeasurement of taxes	32	(319)
Impairments	(286)	(45)
Loss on early extinguishment of debt	(57)	-
Deferred income taxes	(45)	-
Gain on dispositions	407	122
Gain on U.K. natural gas contracts[(a)]	-	37
Income from continuing operations	1,882	716
Discontinued operations	686	747
Net income	$ 2,568	$ 1,463

(a) Amounts relate to natural gas contracts in the U. K. that were accounted for as derivative instruments and recorded at fair value.

United States E&P income increased $199 million from 2009 to 2010. The majority of the income increase was due to higher liquid hydrocarbon and natural gas realizations in 2010, along with higher liquid hydrocarbon sales volumes, partially offset by higher DD&A and higher exploration and operating costs. Exploration expenses were $275 million for 2010, compared to $153 million for 2009, reflecting increased geological and geophysical spending focused on shale plays and exploration dry well expense, primarily the Flying Dutchman well in the Gulf of Mexico.

International E&P income increased $524 million from 2009 to 2010. This increase was primarily related to higher liquid hydrocarbon and natural gas realizations, partially offset by higher exploration expenses and income taxes. Exploration expenses were $223 million for 2010, compared to $154 million for 2009, reflecting higher dry well expense with dry wells in Indonesia, Norway and EG.

OSM segment income decreased $94 million from 2009 to 2010. Cost increases in 2010 associated with the planned turnaround at the Muskeg River mine and the Jackpine mine start-up were in excess of the revenue increase previously discussed. Results for 2010 included after-tax gains on crude oil derivative instruments of $19 million, while the impact of derivatives on 2009 was not significant.

IG segment income increased $52 million from 2009 to 2010. The increase in income was primarily the result of higher realizations for LNG and methanol.

Management s Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

Cash Flows

Net cash provided by continuing operations was $5,434 million in 2011 compared to $4,194 million in 2010 and $3,172 million in 2009. The $1,240 million increase in 2011 and the $1,022 million increase in 2010 primarily reflect increasing average realized prices.

Net cash used in investing activities related to continuing operations totaled $7,174 million in 2011 compared to $2,157 million in 2010 and $2,359 million in 2009. Significant investing activities include acquisitions, additions to property, plant and equipment and asset disposals.

Acquisitions in 2011 included proved and unproved assets in the Eagle Ford shale play in south Texas. See Item 8. Financial Statements and Supplementary Data Note 5 to the consolidated financial statements for further information about the transactions.

The most significant additions to property, plant and equipment relate to our long-term projects, which cross several years. In our E&P segment, exploration and development projects in Angola impacted all three years. Development of fields tied back to the Alvheim FPSO occurred in 2009 and 2010. Spending on U.S. exploration and development projects has been increasing over the years, related to unconventional resource plays and Gulf of Mexico exploration when drilling was allowed. In the OSM segment, the AOSP Expansion 1, which began in 2008, was substantially complete in 2010.

Disposal of assets totaled $518 million, $1,368 million and $812 million in 2011, 2010 and 2009. Several sales of non-core assets in 2011 and acreage farmouts resulted in net proceeds of $518 million. In 2010, we closed the sale of our 20 percent outside-operated undivided interest in the Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola for $1.3 billion. In 2009, we sold all of our operated and outside-operated interests in Ireland and Gabon, reporting the disposals as discontinued operations. We also sold our operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas. See Item 8. Financial Statements and Supplementary Data Note 6 to the consolidated financial statements for more information about dispositions.

Financing activities related to continuing operations resulted in a use of cash of $5,211 million in 2011, but provided cash of $1,343 million in 2010 and $737 million 2009. In connection with the spin-off, we distributed $1.6 billion to MPC in the second quarter of 2011. Early debt repayments of $2,498 million and $500 million occurred in 2011 and 2010. Purchases of common stock used $300 million in cash during 2011. Sources of cash in 2009 included the issuance of $1.5 billion in senior notes. Dividend payments were uses of cash in every year.

Liquidity and Capital Resources

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, the issuance of notes, our $3.0 billion committed revolving credit facility and sales of non-core assets. Because of the alternatives available to us, including internally generated cash flow and access to capital markets, we believe that our short-term and long-term liquidity is adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, dividend payments, defined benefit plan contributions, repayment of debt maturities, share repurchase program and other amounts that may ultimately be paid in connection with contingencies.

Capital Resources

Credit Arrangements and Borrowings

At December 31, 2011, we had $4,815 million in long-term debt outstanding, $141 million of which is due within one year. We do not have any triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings.

At December 31, 2011, we had no borrowings outstanding against our $3 billion revolving credit facility, the vast majority of which has a termination date of May 2013, and no commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

Shelf Registration

We have a universal shelf registration statement filed with the Securities and Exchange Commission, under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

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Cash-Adjusted Debt-To-Capital Ratio

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 20 percent and 14 percent at December 31, 2011 and 2010.

(Dollars in millions)	2011	2010
Long-term debt due within one year	$ 141	$ 295
Long-term debt	4,674	7,601
Total debt	$ 4,815	$ 7,896
Cash	$ 493	$ 3,951
Equity	$ 17,159	$ 23,771
Calculation:		
Total debt	$ 4,815	$ 7,896
Minus cash	493	3,951
Total debt minus cash	4,322	3,945
Total debt	4,815	7,896
Plus equity	17,159	23,771
Minus cash	493	3,951
Total debt plus equity minus cash	$ 21,481	$ 27,716
Cash-adjusted debt-to-capital ratio	20%	14%

Capital Requirements

Capital Spending

Our approved capital, investment and exploration budget for 2012 is $4,822 million. Additional details related to the 2012 budget are discussed in Outlook.

Other Expected Cash Outflows

We plan to make contributions of up to $113 million to our pension plans during 2012. As of December 31, 2011, $141 million of our long-term debt is due in the next twelve months.

Dividends of $0.80 per common share or $567 million were paid during 2011 reflecting quarterly dividends of $0.25 per share in the first two quarters and $0.15 per share in the two quarters after the spin-off of our downstream business. On January 27, 2012, we announced that our Board of Directors had declared a dividend of $0.17 cents per share on Marathon Oil common stock, payable March 12, 2012, to stockholders of record at the close of business on February 16, 2012. This is a 13 percent increase over the dividend paid in the preceding quarter.

Share Repurchase Program

Since January 2006, our Board of Directors has authorized a common share repurchase program totaling $5 billion. As of December 31, 2011, we had repurchased 78 million common shares at a cost of $3,222 million, with 66 million shares purchased for $2,922 million prior to the spin-off of our downstream business and 12 million shares acquired at a cost of $300 million in the third quarter of 2011. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The program s authorization does not include specific price targets or timetables. The timing of purchases under the program will be influenced by cash generated from operations, proceeds from potential asset sales, cash from available borrowings and market conditions.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance (as measured by various factors including cash provided from operating activities), the state of worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate, and, in particular, with respect to borrowings, the levels of our outstanding debt and credit ratings by rating agencies. The discussion of liquidity above also contains forward-looking statements regarding expected capital, investment and exploration spending and planned funding of our pension plans. The forward-looking statements about our capital, investment and exploration budget are based on current expectations, estimates and projections and are not guarantees of future performance. The forward-looking statements about our common share repurchase program are

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based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for liquid hydrocarbons, natural gas and synthetic crude oil, actions of competitors, disruptions or interruptions of our production or oil sands mining and bitumen upgrading operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2011.

(In millions)	Total	2012	2013-2014	2015-2016	Later Years
Long-term debt (excludes interest)[(a)]	$ 4,794	$ 141	$ 274	$ 69	$ 4,310
Lease obligations	275	64	69	53	89
Purchase obligations:					
Oil and gas activities[(b)]	2,709	541	814	549	805
Service and materials contracts[(c)]	1,044	169	198	129	548
Transportation and related contracts	1,303	322	174	129	678
Drilling rigs and fracturing crews	1,079	506	551	22	
Other	276	108	85	28	55
Total purchase obligations	6,411	1,646	1,822	857	2,086
Other long-term liabilities reported in the consolidated balance sheet[(d)]	1,231	176	273	251	531
Total contractual cash obligations[(e)]	$ 12,711	$ 2,027	$ 2,438	$ 1,230	$ 7,016

(a) We anticipate cash payments for interest of $286 million for 2012, $542 million for 2013-2014, $535 million for 2015-2016 and $2,965 million for the remaining years for a total of $4,328 million.

(b) Oil and gas activities include contracts to acquire property, plant and equipment and commitments for oil and gas exploration such as costs related to contractually obligated exploratory work programs that are expensed immediately.

(c) Service and materials contracts include contracts to purchase services such as utilities, supplies and various other maintenance and operating services.

(d) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2021. Also includes amounts for uncertain tax positions.

(e) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1,510 million. See Item 8. Financial Statements and Supplementary Data Note 18 to the consolidated financial statements.

Transactions with Related Parties

We own a 63 percent working interest in the Alba field offshore Equatorial Guinea. Onshore Equatorial Guinea, we own a 52 percent interest in an LPG processing plant, a 60 percent interest in an LNG production facility and a 45 percent interest in a methanol production plant, each through equity method investees. We sell our natural gas from the Alba field to these equity method investees as the feedstock for their production processes. The methanol that is produced is then sold through another equity method investee.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under accounting principles generally accepted in the U.S. Although off-balance sheet arrangements serve a variety of our business purposes, we are not dependent on these arrangements to maintain our liquidity and capital resources, and we are not aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on liquidity and capital resources.

We will issue stand alone letters of credit when required by a business partner. Such letters of credit outstanding at December 31, 2011, 2010 and 2009 aggregated $231 million, $439 million and $224 million. Most of the letters of credit are in support of obligations recorded in the consolidated balance sheet. For example, they are issued to counterparties to insure our payments for outstanding company debt, future abandonment liabilities and prior to June 30, 2011, crude purchases by our downstream business which we spun-off on that date. The decline in the level of our outstanding letters of credit in 2011 is primarily related to the spin-off of our downstream business.

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Outlook

Our Board of Directors approved a capital, investment and exploration budget of $4,822 million for 2012, including budgeted capital expenditures of $4,402 million which represented a 29 percent increase from 2011 spending. Our focus in 2012 continues to be our U.S. liquids-rich growth assets, which account for almost 65 percent of the 2012 budget. Further detail of our budget by segment and asset lifecycle is presented below. For additional information about expected exploration and development activities on specific assets see Item 1. Business.

Exploration and Production

The worldwide exploration and production budget for 2012 is $4,387 million, a 44 percent increase over 2011 capital spending. The exploration and production strategy is based on three key elements: a solid portfolio of base assets, growth assets and impact exploration. Almost two thirds, or $3,041 million of the budget is allocated to our growth assets and almost one half of that is targeted to ramp up our operations in the Eagle Ford shale play in Texas. We will also continue to build on our substantial positions in the Bakken and Anadarko Woodford shale plays and to establish our business in the emerging Niobrara shale play of the DJ Basin. Approximately $2.7 billion of our budget is concentrated in these four U.S. liquids-rich resource plays.

Spending on our base E&P assets is budgeted at $913 million for 2012. These assets include production operations in the Gulf of Mexico, Norway, U.S. conventional oil and gas plays, Equatorial Guinea, the U.K. and Libya which generate much of the cash that will be available for investment in our growth assets and exploration projects.

Impact exploration projects account for 9 percent, or $433 million of the 2012 budget and include conducting seismic surveys and drilling 12 18 gross (6 10 net) wells on prospects in the deepwater Gulf of Mexico, the Iraqi Kurdistan Region and Poland.

The above discussion includes forward-looking statements with respect to anticipated future exploratory and development drilling activity, investments in new and existing resource plays and potential development projects. Some factors which could potentially affect these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, drilling rig availability, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. The foregoing forward-looking statements may be further affected by the inability to obtain or delay in obtaining necessary government and third-party approvals or permits. The offshore developments could further be affected by presently known data concerning size and character of reservoirs, economic recoverability, future drilling success and production experience. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Oil Sands Mining

The Oil Sands Mining segment budget for 2012 is $275 million. The 2012 budget includes funds for the initiation of debottlenecking projects, continued evaluation of Quest CCS and other capital expenditures. A final investment decision on Quest CCS is expected to be made in 2012, and is subject to regulatory approvals, stakeholder engagement, detailed engineering studies, as well as a final joint venture partner agreement.

Corporate and Other

The remaining $160 million of our 2012 budget is split roughly in half between capitalized interest on ongoing projects and other corporate activities. Additionally, $1 million is budgeted for our Integrated Gas segment.

The forward-looking statements about our capital, investment and exploration budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for crude oil and natural gas, actions of competitors, disruptions or interruptions of our production or bitumen mining and upgrading operations due to the shortage of skilled labor and unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response, and other operating and economic considerations.

Management s Discussion and Analysis of Environmental Matters, Litigation and Contingencies

We have incurred and may continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas, and production processes.

Legislation and regulations pertaining to climate change and greenhouse gas emissions have the potential to materially adversely impact our business, financial condition, results of operations and cash flows, including costs of compliance and permitting delays. The extent and magnitude of these adverse impacts cannot be reliably or accurately estimated at this time because specific regulatory and legislative requirements have not been finalized and uncertainty exists with respect to the measures being considered, the costs and the time frames for compliance, and our ability to pass compliance costs on to our customers. For additional information see Item 1A. Risk Factors.

Our environmental expenditures[(a)] related to continuing operations for each of the last three years were:

(In millions)	2011	2010	2009
Capital	$ 122	$ 82	$ 91
Compliance			
Operating and maintenance	35	26	23
Remediation[(b)]	5	1	2
Total	$ 162	$ 109	$ 116

(a) Amounts are determined based on American Petroleum Institute survey guidelines regarding the definition of environmental expenditures.

(b) These amounts include spending charged against remediation reserves, where permissible, but exclude non-cash provisions recorded for environmental remediation.

Our environmental capital expenditures accounted for four percent of capital expenditures for continuing operations in 2011, two percent in 2010 and three percent in 2009.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We comply with all legal requirements regarding the environment, but since not all of them are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

Our environmental capital expenditures related to continuing operations are expected to be $167 million, or three percent, of capital expenditures in 2012. Predictions beyond 2012 can only be broad-based estimates, which have varied, and will continue to vary, due to the ongoing evolution of specific regulatory requirements, the possible imposition of more stringent requirements and the availability of new technologies, among other matters. Based on currently identified projects, we anticipate that environmental capital expenditures will be approximately $205 million in 2013; however, actual expenditures may vary as the number and scope of environmental projects are revised as a result of improved technology or changes in regulatory requirements and could increase if additional projects are identified or additional requirements are imposed.

For more information on environmental regulations that impact us, or could impact us, see Item 1. Business   Environmental Matters, Item 3. Legal Proceedings and Item 1A. Risk Factors.

Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Estimated Quantities of Net Reserves

The estimation of quantities of net reserves is a highly technical process performed by our engineers for liquid hydrocarbons and natural gas, and by outside consultants for synthetic crude oil, which is based upon several underlying assumptions that are subject to change. Estimates of reserves may change, either positively or negatively, as additional information becomes available and as contractual, operational, economic and political conditions change. We evaluate our

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reserves using drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Reserve estimates are based upon an unweighted average of commodity prices in the prior 12-month period, using the closing prices on the first day of each month. These prices are not indicative of future market conditions. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1. Business.

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved liquid hydrocarbon, natural gas and synthetic crude oil reserves.

The existence and the estimated amount of reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depreciated, depleted or amortized into net income and the presentation of supplemental information on oil and gas producing activities. Additionally, both the expected future cash flows to be generated by oil and gas producing properties used in testing such properties for impairment and the expected future taxable income available to realize deferred tax assets also rely, in part, on estimates of quantities of net reserves.

Depreciation and depletion of liquid hydrocarbon, natural gas and synthetic crude oil producing properties is determined by the units-of-production method and could change with revisions to estimated proved reserves. Over the past three years, the impact on our depreciation and depletion rate due to revisions of previous reserve estimates has not been significant to either our E&P or our OSM segments. However, during 2009, the change to presenting oil sands mining reserves as synthetic crude oil under the SEC s revised regulations caused our reported revisions to previous estimates to be near 50 percent of the beginning of the year reserve estimate. This presentation change did not have a significant impact upon the calculation of depreciation, depletion and amortization for our OSM segment. For our E&P segment, on average, a five percent increase in the amount of proved liquid hydrocarbon and natural gas reserves would lower the depreciation and depletion rate by approximately $0.66 per barrel, which would increase pretax income by approximately $87 million annually, based on 2011 production. Conversely, on average, a five percent decrease in the amount of proved liquid hydrocarbon and natural gas reserves would increase the depreciation and depletion rate by approximately $0.72 per barrel and would result in a decrease in pretax income of approximately $96 million annually, based on 2011 production. For our OSM segment, on average, a five percent increase in estimated proved synthetic crude oil reserves would lower the depreciation and depletion rate by approximately $0.62 per barrel and would result in an increase in pretax income of approximately $9 million annually, based on 2011 production. On average, a five percent decrease in estimated proved synthetic crude oil reserves would increase the depreciation and depletion rate by approximately $0.69 per barrel and would result in a decrease in pretax income of approximately $9 million annually, based on 2011 production.

Fair Value Estimates

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and does not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

Level 1 Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.

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Level 3 Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management s best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. We use a market or income approach for recurring fair value measurements and endeavor to use the best information available. See Item 8. Financial Statements and Supplementary Data Note 15 to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurements include:

- impairment assessments of long-lived assets;
- impairment assessments of goodwill;
- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed in those acquisitions; and
- recorded value of derivative instruments

Impairment Assessments of Long-Lived Assets and Goodwill

The need to test long-lived assets and goodwill for impairment can be based on several indicators, including a significant reduction in prices of liquid hydrocarbons, natural gas or synthetic crude oil, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which the property is located.

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate that the carrying value of the assets may not be recoverable. For purposes of impairment evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field for E&P assets and project level for oil sands mining assets. If the sum of the undiscounted estimated pretax cash flows is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value.

Unlike long-lived assets, goodwill must be tested for impairment at least annually, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Goodwill is tested for impairment at the reporting unit level.

Fair value calculated for the purpose of testing our long-lived assets and goodwill for impairment is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- *Future liquid hydrocarbon, natural gas and synthetic crude oil prices*. Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by global market supply and demand. To estimate supply, we consider numerous factors, including the worldwide resource base, depletion rates, and OPEC production policies. We believe demand is largely driven by global economic factors, such as population and income growth, governmental policies, and vehicle stocks. The prices we use in our fair value estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in liquid hydrocarbon, natural gas and synthetic crude oil prices and estimates of such future prices are inherently imprecise.

Estimated quantities of liquid hydrocarbons, natural gas and synthetic crude oil. Such quantities are based on a combination of proved and probable reserves such that the combined volumes represent the most likely expectation of recovery. By definition, probable reserve estimates are less precise than proved reserve estimates.

Expected timing of production. Production forecasts are the outcome of engineer studies which estimate proved and probable reserves. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. The expected timing of production that we use in our fair value estimates is consistent with that used in our planning and capital investment reviews.

Discount rate commensurate with the risks involved. We apply a discount rate to our expected cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. A higher discount rate decreases the net present value of cash flows.

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Future capital requirements. Our estimates of future capital requirements are based on authorized spending and internal forecasts. We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from these projections.

An estimate of the sensitivity to net income resulting from impairment calculations is not practicable, given the numerous assumptions (e.g. reserves, pricing and discount rates) that can materially affect our estimates. That is, unfavorable adjustments to some of the above listed assumptions may be offset by favorable adjustments in other assumptions.

Acquisitions

In accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. The excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values of property, plant and equipment and identifiable intangible assets. The most significant assumptions relate to the estimated fair values allocated to proved and unproved liquid hydrocarbon, natural gas and synthetic crude oil properties. Estimated fair values assigned to assets acquired can have a significant effect on our results of operations in the future. We use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance. During 2011, we completed a business combination in the Eagle Ford shale with an aggregate purchase price of $4.5 billion that was allocated to the assets acquired and liabilities assumed based on their estimated fair values (see Item 8. Financial Statements and Supplementary Data Note 5 to the consolidated financial statements).

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to estimate reserves as described above under Estimated Quantities of Net Reserves, project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Derivatives

We record all derivative instruments at fair value. A large volume of our commodity derivatives are exchange-traded and require few assumptions in arriving at fair value. Fair value estimation for all our derivative instruments is discussed in Item 8. Financial Statements and Supplementary Data Note 15 to the consolidated financial statements. Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Income Taxes

We are subject to income taxes in numerous taxing jurisdictions worldwide. Estimates of income taxes to be recorded involve interpretation of complex tax laws and assessment of the effects of foreign taxes on our U.S. federal income taxes.

We have recorded deferred tax assets and liabilities for temporary differences between book basis and tax basis, tax credit carryforwards and operating loss carryforwards. We routinely assess the realizability of our deferred tax assets and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. In assessing the need for additional or adjustments to existing valuation allowances, we consider the preponderance of evidence concerning the realization of the deferred tax asset. We must consider any prudent and feasible tax planning strategies that might minimize the amount of deferred tax liabilities recognized or the amount of any valuation allowance recognized against deferred tax assets, if we can implement the strategies and we expect to implement them in the event the forecasted conditions actually occur. Assumptions related to the permanent reinvestment of the earnings of our foreign subsidiaries are reconsidered quarterly to give effect to changes in our portfolio of producing properties and in our tax profile.

Our net deferred tax assets, after valuation allowances, are expected to be realized through our future taxable income and the reversal of temporary differences. Numerous judgments and assumptions are inherent in the estimation of future taxable income, including factors such as future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices) and the assessment of the effects of foreign taxes on our U.S. federal income taxes. The estimates and assumptions used in determining future taxable income are consistent with those used in our planning and capital investment reviews. We consider proved and, in some cases, probable and possible reserves related to our existing producing properties, as well as estimated quantities of liquid hydrocarbon, natural gas and synthetic crude oil related to undeveloped discoveries if, in our judgment, it is likely that development plans will be approved in the foreseeable future. Assumptions regarding our ability to realize the U.S. federal benefit of foreign tax

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credits are based on certain estimates concerning future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and our tax profile in the year that such credits may be claimed.

Pension and Other Postretirement Benefit Obligations

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the following:

- the discount rate for measuring the present value of future plan obligations;
- the expected long-term return on plan assets;
- the rate of future increases in compensation levels; and
- health care cost projections.

We develop our demographics and utilize the work of third-party actuaries to assist in the measurement of these obligations. We have selected different discount rates for our funded U.S. pension plan and our unfunded U.S. retiree health care plan due to the different projected benefit payment patterns. In determining the assumed discount rates, our methods include a review of market yields on high-quality corporate debt and use of our third-party actuary s discount rate model. This model calculates an equivalent single discount rate for the projected benefit plan cash flows using a yield curve derived from AA bond yields. The yield curve represents a series of annualized individual spot discount rates from 0.5 to 99 years. The bonds used are rated AA or higher by a recognized rating agency, only non-callable bonds are included and outlier bonds (bonds that have a yield to maturity that significantly deviates from the average yield within each maturity grouping) are removed. Each issue is required to have at least $250 million par value outstanding. The constructed yield curve is based on those bonds representing the 50 percent highest yielding issuance within each defined maturity group.

Of the assumptions used to measure the yearend obligations and estimated annual net periodic benefit cost, the discount rate has the most significant effect on the periodic benefit cost reported for the plans. Decreasing the discount rates of 4.45 percent for our U.S. pension plan and 4.90 percent for our other U.S. postretirement benefit plan by 0.25 would increase pension obligations and other postretirement benefit plan obligations by $43 million and $9 million and would increase annual defined benefit pension expense by $5 million and would not have a significant impact on other postretirement benefit plan expense.

The asset rate of return assumption considers the asset mix of the plans (targeted at approximately 75 percent equity securities and 25 percent debt securities for the U.S. funded pension plan through 2011, 65 percent equity securities and 35 percent debt securities for the U.S. funded pension plan beginning in 2012 and 70 percent equity securities and 30 percent debt securities for the international funded pension plans), past performance and other factors. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields. Our long-term asset rate of return assumption is compared to those of other companies and to our historical returns for reasonableness. Decreasing the 7.75 percent asset rate of return assumption by 0.25 would not have a significant impact on our defined benefit pension expense.

Compensation change assumptions are based on historical experience, anticipated future management actions and demographics of the benefit plans.

Health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends.

Item 8. Financial Statements and Supplementary Data Note 20 to the consolidated financial statements includes detailed information about the assumptions used to calculate the components of our annual defined benefit pension and other postretirement plan expense, as well as the obligations and accumulated other comprehensive income reported on the balance sheets.

Contingent Liabilities

We accrue contingent liabilities for environmental remediation, tax deficiencies related to operating taxes, and litigation claims when such contingencies are probable and estimable. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their interpretation; additional information on the extent and nature of site contamination; and improvements in technology. Our in-house legal counsel regularly assesses these contingent liabilities. In certain circumstances, outside legal counsel is utilized.

We generally record losses related to these types of contingencies as cost of revenues or selling, general and administrative expenses in the consolidated statements of income, except for tax contingencies unrelated to income taxes,

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which are recorded as other taxes. For additional information on contingent liabilities, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Management s Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.

Accounting Standards Not Yet Adopted

The FASB and the IASB issued joint disclosure requirements in December 2011 designed to enhance disclosures about offsetting assets and liabilities that will enable financial statement users to evaluate the effect or potential effect of netting arrangements on an entity s financial position. Entities are required to disclose both gross information and net information about financial instruments and derivative instruments that are either offset in the statement of financial position or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. These disclosures are effective for us beginning the first quarter of 2013 and must be made retrospectively for comparable periods. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

In September 2011, the FASB amended accounting standards to simplify how entities test goodwill for impairment. The amendment reduces complexity by allowing an entity the option to make a qualitative evaluation of whether it is necessary to perform the two-step goodwill impairment test. The amendment is effective for our interim and annual periods beginning with the first quarter of 2012. Early adoption is permitted, but we were unable to do so because our 2011 annual goodwill impairment testing was completed prior to the issuance of the amendment. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

The FASB amended the reporting standards for comprehensive income in June 2011 to eliminate the option to present the components of Other Comprehensive Income (OCI) as part of the statement of changes in stockholders equity. All non-owner changes in stockholders equity are required to be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of OCI, and the total of comprehensive income. The presentation of items that are reclassified from OCI to net income on the income statement is also required. The amendments did not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. The amendments are effective for us beginning with the first quarter of 2012, except for the presentation of reclassifications, which has been deferred. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

In May 2011, the FASB issued an update amending the accounting standards for fair value measurement and disclosure, resulting in common principles and requirements under U.S. GAAP and IFRS. The amendments change the wording used to describe certain of the U.S. GAAP requirements either to clarify the intent of existing requirements, to change measurement or expand disclosure principles or to conform to the wording used in IFRS. The amendments are to be applied prospectively and will be effective for our interim and annual periods beginning with the first quarter of 2012. Early application is not permitted. We do not expect adoption of these amendments to have a significant impact on our consolidated results of operations, financial position or cash flows.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risks related to the volatility of liquid hydrocarbon, natural gas and synthetic crude oil prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. We are also exposed to market risks related to changes in interest rates and foreign currency exchange rates. We employ various strategies, including the use of financial derivative instruments, to manage the risks related to these fluctuations. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price or rate changes related to the underlying commodity or financial transaction.

We believe that our use of derivative instruments, along with our risk assessment procedures and internal controls, does not expose us to material adverse consequences. While the use of derivative instruments could materially affect our results of operations in particular quarterly or annual periods, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity.

See Item 8. Financial Statements and Supplementary Data Notes 15 and 16 to the consolidated financial statement for more information about the fair value measurement of our derivatives, as well as the amounts recorded in our consolidated balance sheets and statements of income for those which qualify as hedges and those not designated as hedges.

Commodity Price Risk

Our strategy is to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. However, management will occasionally protect prices on forecasted sales, as deemed appropriate. We use a variety of commodity derivative instruments, including futures, forwards, swaps and combinations of options, as part of an overall program to manage commodity price risk in our different businesses.

We regularly use commodity derivative instruments in the E&P segment to manage natural gas price risk during the time that the natural gas is held in storage before it is sold or related to our supply optimization activities.

The fair value of commodity derivatives outstanding at December 31, 2011 was less than $1 million. For these derivatives, hypothetical 10 percent and 25 percent increases and decreases in commodity prices would not significantly impact income from operations (IFO). We evaluate our portfolio of commodity derivative instruments on an ongoing basis and add or revise strategies in anticipation of changes in market conditions and in risk profiles.

Interest Rate Risk

We are impacted by interest rate fluctuations which affect the fair value of certain financial instruments. We manage our exposure to interest rate movements by utilizing financial derivative instruments. The primary objective of this program is to reduce our overall cost of borrowing by managing the mix of fixed and floating interest rate debt in our portfolio. As of December 31, 2011, we had multiple interest rate swap agreements with a total notional amount of $600 million at a weighted-average, LIBOR-based, floating rate of 4.76 percent. These interest rate swaps are designated as fair value hedges, which effectively results in an exchange of existing obligations to pay fixed interest rates for obligations to pay floating rates.

Sensitivity analysis of the projected incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of December 31, 2011, is provided in the following table.

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities)[(a)]		
Interest rate swap agreements	$ 5 [(b)]	$ 4
Long-term debt, including amounts due within one year	$ (5,479) [(b)]	$ (231)

(a) Fair values of cash and cash equivalents, receivables, accounts payable and accrued interest approximate carrying value and are relatively insensitive to changes in interest rates due to the short-term maturity of the instruments. Accordingly, these instruments are excluded from the table.

(b) Fair value was based on market prices where available, or current borrowing rates for financings with similar terms and maturities.

At December 31, 2011, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value.

Foreign Currency Exchange Rate Risk

We may manage our exposure to foreign currency exchange rates by utilizing forward and option contracts. The primary objective of this program is to reduce our exposure to movements in foreign currency exchange rates by locking in such rates. There were no foreign currency forward or option contracts open at December 31, 2011.

Counterparty Risk

We are also exposed to financial risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is reviewed and master netting agreements are used when appropriate.

Safe Harbor

These quantitative and qualitative disclosures about market risk include forward-looking statements with respect to management s opinion about risks associated with the use of derivative instruments. These statements are based on certain assumptions with respect to market prices and industry supply of and demand for liquid hydrocarbons, natural gas and synthetic crude oil. If these assumptions prove to be inaccurate, future outcomes with respect to our use of derivative instruments may differ materially from those discussed in the forward-looking statements.

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Item 8. Financial Statements and Supplementary Data

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Management s Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

The accompanying consolidated financial statements of Marathon Oil Corporation and its consolidated subsidiaries (Marathon Oil) are the responsibility of management and have been prepared in conformity with accounting principles generally accepted in the Unites States of America. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

Marathon Oil seeks to assure the objectivity and integrity of its financial records by careful selection of its managers, by organization arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit and Finance Committee. This Committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

/s/ Clarence P. Cazalot, Jr.	/s/ Janet F. Clark	/s/ Michael K. Stewart
Chairman, President and	*Executive Vice President and*	*Vice President, Finance and Accounting, Controller and Treasurer*
Chief Executive Officer	*Chief Financial Officer*	

Management s Report on Internal Control over Financial Reporting

To the Stockholders of Marathon Oil Corporation:

Marathon Oil s management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a 15(f) under the Securities Exchange Act of 1934). An evaluation of the design and 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, was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on the results of this evaluation, Marathon Oil s management concluded that its internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of Marathon Oil s internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent public accounting firm, as stated in their report which is included herein.

/s/ Clarence P. Cazalot, Jr.	/s/ Janet F. Clark
Chairman, President and	*Executive Vice President*
Chief Executive Officer	*and Chief Financial Officer*

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Report of Independent Registered Public Accounting Firm

To the Stockholders of Marathon Oil Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Marathon Oil Corporation and its subsidiaries (the Company) at December 31, 2011, and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, 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 Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Houston, Texas

February 29, 2012

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MARATHON OIL CORPORATION

Consolidated Statements of Income

(In millions, except per share data)	2011	2010	2009
Revenues and other income:			
Sales and other operating revenues	$ 14,603	$ 11,634	$ 8,465
Sales to related parties	60	56	59
Income from equity method investments	462	344	268
Net gain on disposal of assets	103	766	202
Other income	54	73	90
Total revenues and other income	15,282	12,873	9,084
Costs and expenses:			
Cost of revenues (excludes items below)	6,225	4,786	3,170
Purchases from related parties	250	172	146
Depreciation, depletion and amortization	2,266	2,056	1,934
Impairments	310	447	18
General and administrative expenses	544	491	451
Other taxes	230	199	173
Exploration expenses	644	498	307
Total costs and expenses	10,469	8,649	6,199
Income from operations	4,813	4,224	2,885
Net interest and other	(107)	(75)	(122)
Loss on early extinguishment of debt	(279)	(92)	-
Income from continuing operations before income taxes	4,427	4,057	2,763
Provision for income taxes	2,720	2,175	2,047
Income from continuing operations	1,707	1,882	716
Discontinued operations	1,239	686	747
Net income	$ 2,946	$ 2,568	$ 1,463
Per Share Data			
Basic:			
Income from continuing operations	$ 2.40	$ 2.65	$ 1.01
Discontinued operations	$ 1.75	$ 0.97	$ 1.05
Net income	$ 4.15	$ 3.62	$ 2.06
Diluted:			
Income from continuing operations	$ 2.39	$ 2.65	$ 1.01
Discontinued operations	$ 1.74	$ 0.96	$ 1.05
Net income	$ 4.13	$ 3.61	$ 2.06
Dividends	$ 0.80	$ 0.99	$ 0.96
Weighted average shares:			
Basic	710	710	709
Diluted	714	712	711

The accompanying notes are an integral part of these consolidated financial statements.

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MARATHON OIL CORPORATION

Consolidated Statements of Comprehensive Income

(In millions)	2011	2010	2009
Net income	$ 2,946	$ 2,568	$ 1,463
Other comprehensive income (loss)			
Postretirement and post-employment plans			
Change in actuarial gain (loss)	16	(76)	(564)
Spin-off downstream business	968	-	-
Income tax benefit (provision) on postretirement and post-employment plans	(357)	7	208
Postretirement and post-employment plans, net of tax	627	(69)	(356)
Derivative hedges			
Net unrecognized gain	9	5	24
Spin-off downstream business	(7)	-	-
Income tax benefit (provision) on derivative hedges	(1)	1	(12)
Derivative hedges, net of tax	1	6	12
Foreign currency translation and other			
Unrealized gain (loss)	(1)	-	4
Income tax provision on foreign currency translation and other	-	-	(1)
Foreign currency translation and other, net of tax	(1)	-	3
Other comprehensive income (loss)	627	(63)	(341)
Comprehensive income	$ 3,573	$ 2,505	$ 1,122

The accompanying notes are an integral part of these consolidated financial statements.

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MARATHON OIL CORPORATION

Consolidated Balance Sheets

(In millions, except per share data)	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 493	$ 3,951
Receivables, less allowance for doubtful accounts of $0 and $7	1,917	5,972
Receivables from related parties	35	58
Inventories	361	3,453
Prepayments	96	92
Deferred tax assets	99	-
Other current assets	223	303
Total current assets	3,224	13,829
Equity method investments	1,383	1,802
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $17,248 and $19,805	25,324	32,222
Goodwill	536	1,380
Other noncurrent assets	904	781
Total assets	$ 31,371	$ 50,014
Liabilities		
Current liabilities:		
Accounts payable	$ 1,864	$ 8,000
Payables to related parties	18	49
Payroll and benefits payable	193	418
Accrued taxes	2,015	1,447
Deferred tax liabilities	5	324
Other current liabilities	158	580
Long-term debt due within one year	141	295
Total current liabilities	4,394	11,113
Long-term debt	4,674	7,601
Deferred income taxes	2,544	3,569
Defined benefit postretirement plan obligations	789	2,171
Asset retirement obligations	1,510	1,354
Deferred credits and other liabilities	301	435
Total liabilities	14,212	26,243
Commitments and contingencies		
Stockholders Equity		
Preferred stock - no shares issued or outstanding (no par value, 26 million shares authorized)	-	-
Common stock:		
Issued 770 million and 770 million shares (par value $1 per share, 1.1 billion shares authorized)	770	770
Securities exchangeable into common stock no shares issued or outstanding (no par value, 29 million shares authorized)	-	-
Held in treasury, at cost 66 million and 60 million shares	(2,716)	(2,665)
Additional paid-in capital	6,680	6,756
Retained earnings	12,788	19,907

Accumulated other comprehensive loss		(370)		(997)
Total equity of Marathon Oil s stockholders		17,152		23,771
Noncontrolling interest		7		-
Total equity		17,159		23,771
Total liabilities and equity	$	31,371	$	50,014

The accompanying notes are an integral part of these consolidated financial statements.

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MARATHON OIL CORPORATION

Consolidated Statements of Cash Flows

(In millions)	2011	2010	2009
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income	$ 2,946	$ 2,568	$ 1,463
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations	(1,239)	(686)	(747)
Loss on early extinguishment of debt	279	92	-
Deferred income taxes	(182)	(489)	546
Depreciation, depletion and amortization	2,266	2,056	1,934
Impairments	310	447	18
Pension and other postretirement benefits, net	64	31	(17)
Exploratory dry well costs and unproved property impairments	357	225	81
Net gain on disposal of assets	(103)	(766)	(202)
Equity method investments, net	47	56	34
Changes in:			
Current receivables	8	(409)	(188)
Inventories	33	(71)	(104)
Current accounts payable and accrued liabilities	485	1,018	308
All other operating, net	163	122	46
Net cash provided by continuing operations	5,434	4,194	3,172
Net cash provided by discontinued operations	1,090	1,676	2,096
Net cash provided by operating activities	6,524	5,870	5,268
Investing activities:			
Acquisitions	(4,470)	-	-
Additions to property, plant and equipment	(3,295)	(3,536)	(3,349)
Disposal of assets	518	1,368	812
Investments - return of capital	59	58	59
Investing activities of discontinued operations	(493)	(464)	(2,879)
All other investing, net	14	(47)	119
Net cash used in investing activities	(7,667)	(2,621)	(5,238)
Financing activities:			
Borrowings	-	-	1,491
Debt issuance costs	-	-	(11)
Debt repayments	(2,877)	(653)	(68)
Purchases of common stock	(300)	-	-
Issuance of common stock	77	12	4
Dividends paid	(567)	(704)	(679)
Financing activities of discontinued operations	2,916	(12)	(13)
Distribution in spin-off	(1,622)	-	-
All other financing, net	78	2	-
Net cash provided by (used in) financing activities	(2,295)	(1,355)	724
Effect of exchange rate changes on cash	(20)	-	18

Net increase (decrease) in cash and cash equivalents	(3,458)	1,894	772
Cash and cash equivalents at beginning of period	3,951	2,057	1,285
Cash and cash equivalents at end of period	$ 493	$ 3,951	$ 2,057

The accompanying notes are an integral part of these consolidated financial statements.

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MARATHON OIL CORPORATION

Consolidated Statements of Stockholders Equity

	Equity Attributable to Marathon Oil Stockholders								
(In millions)	Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Total Stockholders Equity
January 1, 2009 Balance	$ -	$ 767	$ -	$ (2,720)	$ 6,696	$ 17,259	$ (593)	$ -	$ 21,409
Shares issued - stock based compensation	-	-	-	20	(9)	-	-	-	11
Shares exchanged	-	2	-	-	(2)	-	-	-	-
Shares repurchased	-	-	-	(6)	-	-	-	-	(6)
Stock-based compensation	-	-	-	-	53	-	-	-	53
Net income	-	-	-	-	-	1,463	-	-	1,463
Other comprehensive loss	-	-	-	-	-	-	(341)	-	(341)
Dividends paid	-	-	-	-	-	(679)	-	-	(679)
December 31, 2009 Balance	$ -	$ 769	$ -	$ (2,706)	$ 6,738	$ 18,043	$ (934)	$ -	$ 21,910
Shares issued - stock based compensation	-	-	-	46	(12)	-	-	-	34
Shares exchanged	-	1	-	-	(1)	-	-	-	-
Shares repurchased	-	-	-	(5)	-	-	-	-	(5)
Stock-based compensation	-	-	-	-	31	-	-	-	31
Net income	-	-	-	-	-	2,568	-	-	2,568
Other comprehensive loss	-	-	-	-	-	-	(63)	-	(63)
Dividends paid	-	-	-	-	-	(704)	-	-	(704)
December 31, 2010 Balance	$ -	$ 770	$ -	$ (2,665)	$ 6,756	$ 19,907	$ (997)	$ -	$ 23,771
Shares issued - stock based compensation	-	-	-	257	(85)	-	-	-	172
Shares repurchased	-	-	-	(308)	-	-	-	-	(308)
Stock-based compensation	-	-	-	-	4	-	-	-	4
Net income	-	-	-	-	-	2,946	-	-	2,946
Other comprehensive income	-	-	-	-	-	-	40	-	40
Dividends paid	-	-	-	-	-	(567)	-	-	(567)
Purchase of subsidiary shares from non-controlling interest	-	-	-	-	-	-	-	7	7
Spin-off of downstream business	-	-	-	-	5	(9,498)	587	-	(8,906)
December 31, 2011 Balance	$ -	$ 770	$ -	$ (2,716)	$ 6,680	$ 12,788	$ (370)	$ 7	$ 17,159

(Shares in millions)	Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock
January 1, 2009 Balance	3	767	3	(61)
Shares exchanged	(2)	2	(2)	-
December 31, 2009 Balance	1	769	1	(61)
Shares issued - stock based compensation	-	-	-	1
Shares exchanged	(1)	1	(1)	-

December 31, 2010 Balance	-	770	-	(60)
Shares issued - stock based compensation	-	-	-	6
Shares repurchased	-	-	-	(12)
December 31, 2011 Balance	-	770	-	(66)

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION

Notes to Consolidated Financial Statements

1. Summary of Principal Accounting Policies

We are engaged in worldwide exploration, production and marketing of liquid hydrocarbons and natural gas; oil sands mining and bitumen transportation and upgrading in Canada; and production and marketing of products manufactured from natural gas, such as LNG and methanol in EG.

Principles applied in consolidation These consolidated financial statements include the accounts of our majority-owned, controlled subsidiaries and variable interest entities for which we are the primary beneficiary.

Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. This includes entities in which we hold majority ownership but the minority shareholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees.

Equity method investments are carried at our share of net assets plus loans and advances. Such investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in net income. Differences in the basis of the investments and the separate net asset value of the investees, if any, are amortized into net income over the remaining useful lives of the underlying assets, except for the excess related to goodwill.

Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

As a result of the spin-off of our downstream business (see Note 3), the results of operations and cash flows for the downstream business have been classified as discontinued operations for all periods presented. The disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations unless otherwise stated.

Use of estimates The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Foreign currency transactions The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

Revenue recognition Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. Costs associated with revenues are recorded in cost of revenues.

In the lower 48 states of the U.S., production volumes of liquid hydrocarbons and natural gas are sold immediately and transported to market. In Alaska and international locations, liquid hydrocarbon and natural gas production volumes may be stored as inventory and sold at a later time. In Canada, mined bitumen is first processed through an upgrader and then sold as synthetic crude oil. Both bitumen and synthetic crude oil may be stored as inventory.

We follow the sales method of accounting for crude oil and natural gas production imbalances and would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. Imbalances have not been significant in the periods presented.

Cash and cash equivalents Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

Accounts receivable The majority of our receivables are from joint interest owners in properties we operate, or purchasers of liquid hydrocarbons, are recorded at invoiced amounts and do not bear interest. We determine the allowance for doubtful accounts based on historical write-off experience. Past-due balances over 180 days are reviewed individually for collectability.

Inventories Inventories are carried at the lower of cost or market value. The majority of our inventories are recorded at average cost. The last-in, first-out (LIFO) method is used for domestic natural gas inventory.

We may enter into a contract to sell a particular quantity and quality of crude oil at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements as exchanges of inventory.

MARATHON OIL CORPORATION

Notes to Consolidated Financial Statements

Derivative instruments We may use derivatives to manage a portion of our exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk. All derivative instruments are recorded at fair value. Commodity derivatives are reflected on our consolidated balance sheet on a net basis by brokerage firm, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, interest rate risk and foreign currency exchange rate risk related to operating expenditures are classified in operating activities with the underlying transactions. Cash flows related to derivatives used to manage exchange rate risk related to capital expenditures denominated in foreign currencies are classified in investing activities with the underlying transactions. Our derivative instruments contain no significant contingent credit features.

Cash flow hedges We may use foreign currency forwards and options to manage foreign currency risk associated with anticipated transactions, primarily expenditures for capital projects denominated in certain foreign currencies, and designate them as cash flow hedges. The effective portion of changes in fair value is recognized in other comprehensive income (OCI) and is reclassified to net income when the underlying forecasted transaction is recognized in net income. Any ineffective portion is recognized in net interest and other as it occurs. For a discontinued cash flow hedge, prospective changes in the fair value of the derivative are recognized in net income. The accumulated gain or loss recognized in OCI at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in OCI is immediately reclassified into net income.

We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings and designate them as cash flow hedges. No such derivatives were outstanding at December 31, 2011 and 2010.

Fair value hedges We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio and we may use commodity derivative instruments to manage the price risk on natural gas that we purchase to be marketed with our natural gas production. Changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

Derivatives not designated as hedges Derivatives that are not designated as hedges may include commodity derivatives used primarily to manage price risk on the forecasted sale of crude oil, natural gas and synthetic crude oil that we produce. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

Concentrations of credit risk All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

Property, plant and equipment We use the successful efforts method of accounting for oil and gas producing activities, which include our bitumen mining and upgrading.

Property acquisition costs Costs to acquire mineral interests in traditional oil and natural gas properties or in oil sands mines, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells and to construct or expand oil sand mines and upgrading facilities are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed at least quarterly.

Depreciation, depletion and amortization Capitalized costs to acquire oil and natural gas properties, which include our bitumen mining and upgrading facilities, are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities are depreciated on a straight-line basis over their estimated useful lives which range from 3 to 43 years.

Property, plant and equipment unrelated to oil and gas producing activities is recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which range from 3 to 40 years.

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Impairments We evaluate our oil and gas producing properties, including capitalized costs of exploratory wells, development costs and our bitumen mining and upgrading facilities, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure. Impairment of proved properties is required when the carrying value exceeds the related undiscounted future net cash flows based on proved and probable reserves. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors in addition to the use of an undiscounted future net cash flow approach. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage are also considered. Unproved property investments deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows. Impairment expense for unproved oil and natural gas properties is reported in exploration expenses.

Dispositions When property, plant and equipment depreciated on an individual basis are sold or otherwise disposed of, any gains or losses are reported in net income. Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale. Proceeds from the disposal of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income until net book value is reduced to zero.

Goodwill Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to operating expense.

Major maintenance activities Costs for planned major maintenance are expensed in the period incurred. These types of costs include contractor repair services, materials and supplies, equipment rentals and our labor costs.

Environmental costs Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed and determinable.

Asset retirement obligations The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities, which include our bitumen mining facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, mine assets, gathering systems, wells and related structures and restoration costs of land and seabed, including those leased. Estimates of these costs are developed for each property based on the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals. Asset retirement obligations have not been recognized for certain of our international oil and gas producing facilities as we currently do not have a legal obligation associated with the retirement of those facilities. Asset retirement obligations have not been recognized for the removal of materials and equipment from or the closure of certain bitumen upgrading assets because the fair value cannot be reasonably estimated since the settlement dates of the obligations are indeterminate.

Current inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and gas production facilities, which include our bitumen mining facilities, while accretion escalates over the lives of the assets.

Deferred income taxes Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several

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interrelated factors. These factors include our expectation to generate sufficient future taxable income including future foreign source income, tax credits, operating loss carryforwards and management s intent regarding the permanent reinvestment of the income from certain foreign subsidiaries.

Stock based compensation arrangements The fair value of stock options, stock options with tandem stock appreciation rights (SARs) and stock-settled SARs (stock option awards) is estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management s best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. Of the required assumptions, the expected life of the stock option award and the expected volatility of our stock price have the most significant impact on the fair value calculation. We have utilized historical data and analyzed current information which reasonably support these assumptions.

The fair value of our restricted stock awards and common stock units is determined based on the fair market value of our common stock on the date of grant.

Our stock-based compensation expense is recognized based on management s best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods. Unearned stock-based compensation is charged to stockholders equity when restricted stock awards are granted. Compensation expense is recognized over the vesting period and is adjusted if conditions of the restricted stock award are not met. Options with tandem SARs are classified as a liability and are remeasured at fair value each reporting period until settlement.

2. Accounting Standards

Not Yet Adopted

The FASB and the IASB issued joint disclosure requirements in December 2011 designed to enhance disclosures about offsetting assets and liabilities that will enable financial statement users to evaluate the effect or potential effect of netting arrangements on an entity s financial position. Entities are required to disclose both gross information and net information about financial instruments and derivative instruments that are either offset in the statement of financial position or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. These disclosures are effective for us beginning the first quarter of 2013 and must be made retrospectively for comparable periods. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

In September 2011, the FASB amended accounting standards to simplify how entities test goodwill for impairment. The amendment reduces complexity by allowing an entity the option to make a qualitative evaluation of whether it is necessary to perform the two-step goodwill impairment test. The amendment is effective for our interim and annual periods beginning with the first quarter of 2012. Early adoption is permitted, but we were unable to do so because our 2011 annual goodwill impairment testing was completed prior to the issuance of the amendment. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

The FASB amended the reporting standards for comprehensive income in June 2011 to eliminate the option to present the components of OCI as part of the statement of changes in stockholders equity. All non-owner changes in stockholders equity are required to be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of OCI, and the total of comprehensive income. The presentation of items that are reclassified from OCI to net income on the income statement is also required. The amendments did not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. The amendments are effective for us beginning with the first quarter of 2012, except for the presentation of reclassifications, which has been deferred. Adoption of this amendment will not have a significant impact on our consolidated results of operations, financial position or cash flows.

In May 2011, the FASB issued an update amending the accounting standards for fair value measurement and disclosure, resulting in common principles and requirements under U.S. GAAP and IFRS. The amendments change the wording used to describe certain of the U.S. GAAP requirements either to clarify the intent of existing requirements, to change measurement or expand disclosure principles or to conform to the wording used in IFRS. The amendments are to be applied prospectively and will be effective for our interim and annual periods beginning with the first quarter of 2012. Early application is not permitted. We do not expect adoption of these amendments to have a significant impact on our consolidated results of operations, financial position or cash flows.

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Recently Adopted

Oil and Gas Reserve Estimation and Disclosure standards were issued by the FASB in January 2010, which align the FASB s reporting requirements with the below requirements of the SEC. The FASB also addressed the impact of changes in the SEC s rules and definitions on accounting for oil and gas producing activities. Similar to the SEC requirements, the FASB requirements were effective for periods ending on or after December 31, 2009. Initial adoption did not have an impact on our consolidated results of operations, financial position or cash flows. The effect on depreciation, depletion and amortization expense subsequent to adoption, as compared to prior periods, was not significant. The required disclosures are presented in Supplementary Information on Oil and Gas Producing Activities (Unaudited).

In December 2008, the SEC announced that it had approved revisions to its oil and gas reporting disclosures. The new disclosure requirements include provisions that:

- Introduce a new definition of oil and gas producing activities. This new definition allows companies to include volumes in their reserve base from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.
- Report oil and gas reserves using an unweighted average price using the prior 12-month period, based on the closing prices on the first day of each month, rather than year-end prices.
- Permit companies to disclose their probable and possible reserves on a voluntary basis.
- Require companies to provide additional disclosure regarding the aging of proved undeveloped reserves.
- Permit the use of reliable technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.
- Replace the existing certainty test for areas beyond one offsetting drilling unit from a productive well with a reasonable certainty test.
- Require additional disclosures regarding the qualifications of the chief technical person who oversees the company s overall reserve estimation process. Additionally, disclosures regarding internal controls surrounding reserve estimation, as well as a report addressing the independence and qualifications of its reserves preparer or auditor are required.
- Require separate disclosure of reserves in foreign countries if they represent 15 percent or more of total proved reserves, based on barrels of oil equivalent.

As with the FASB standards described above, adoption did not have an impact on our consolidated results of operations, financial position or cash flows. The additional disclosures required by the SEC can be found in Item 1. Business Reserves.

3. Spin-off of Downstream Business

On June 30, 2011, the spin-off of the downstream business was completed, creating two independent energy companies: Marathon Oil and MPC. On June 30, 2011, stockholders of record as of 5:00 p.m. Eastern Daylight Savings time on June 27, 2011 (the Record Date) received one common share of MPC stock for every two common shares of Marathon stock held as of the Record Date.

In order to affect the spin-off and govern our relationship with MPC after the spin-off, we entered into a Separation and Distribution Agreement, a Tax Sharing Agreement, an Employee Matters Agreement and a Transition Services Agreement. The Separation and Distribution Agreement governed the separation of the downstream business, the distribution of MPC s shares of common stock to our stockholders, transfer of assets and intellectual property, and other matters related to our relationship with MPC. The Separation and Distribution Agreement provides for cross-indemnities between Marathon Oil and MPC. In general, we have agreed to indemnify MPC for any liabilities relating to our historical oil and gas exploration and production operations, oil sands mining operations and integrated gas operations, and MPC has agreed to indemnify us for any liabilities relating to the historical downstream operations.

The Tax Sharing Agreement governs the respective rights, responsibilities and obligations of Marathon Oil and MPC with respect to taxes and tax benefits, the filing of tax returns, the control of audits and other tax matters. In addition, the Tax Sharing Agreement reflects each company s rights and obligations related to taxes that are attributable to periods prior to and including the Separation date and taxes resulting from transactions effected in connection with the Separation. In general, under the Tax Sharing Agreement, Marathon Oil is responsible for all U.S. federal, state, local and foreign income taxes attributable to Marathon Oil or any of its subsidiaries for any tax period that begins after the date of the spin-off, and MPC is responsible for all taxes attributable to it or its subsidiaries, whether accruing before, on or after the spin-off. The Tax Sharing Agreement contains covenants intended to protect the tax-free status of the spin-off. These covenants may restrict the ability of Marathon Oil and MPC to pursue strategic or other transactions that otherwise could maximize the values of their respective businesses and may discourage or delay a change of control of either company.

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The Employee Matters Agreement contains provisions concerning benefit protection for employees who became MPC employees prior to December 31, 2011, treatment of holders of Marathon stock options, stock appreciation rights, restricted stock and restricted stock units, and cooperation between Marathon Oil and MPC in the sharing of employee information and maintenance of confidentiality. Unvested equity-based compensation awards were converted to awards of the entity where the employee holding them is working post-separation. For vested equity-based compensation awards, employees received both Marathon Oil and MPC awards.

Under the Transition Services Agreement, Marathon Oil and MPC are providing and/or making available various administrative services and assets to each other, for up to a one-year period beginning on the distribution date of the spin-off. The services include: administrative services; accounting services; audit services; health, environmental and safety services; human resource services; information technology services; legal services; natural gas administration services; tax services; and treasury services. In consideration for such services, the companies are paying fees to the other for the services provided, and these fees are generally in amounts intended to allow the party providing services to recover all of its direct and indirect costs incurred in providing these services.

The following table presents the carrying value of assets and liabilities of MPC, immediately preceding the June 30, 2011 spin-off.

(In millions)		
Current assets:		
Cash and cash equivalents	$	1,622
Receivables		5,041
Inventories		3,679
Other current assets		170
Total current assets of discontinued operations		10,512
Equity method investments		323
Property, plant and equipment		11,935
Goodwill		847
Other noncurrent assets		351
Total assets of discontinued operations	$	23,968
Current liabilities:		
Accounts payable	$	7,329
Payroll and benefits payable		222
Accrued and deferred taxes		443
Other current liabilities		461
Long-term debt due within one year		12
Total current liabilities of discontinued operations		8,467
Long-term debt		3,262
Deferred income taxes		1,568
Defined benefit postretirement plan obligations		1,489
Deferred credits and other liabilities		276
Total liabilities of discontinued operations	$	15,062

The results of operations of our downstream business have been reported as discontinued operations. The table below shows selected financial information reported in discontinued operations related to the spin-off.

(In millions)	2011	2010	2009
Revenues applicable to discontinued operations	$ 38,602	$ 62,488	$ 45,529
Pretax income from discontinued operations	$ 2,012	$ 1,065	$ 894

4. Variable Interest Entities

The owners of the AOSP, in which we hold a 20 percent undivided interest, contracted with a wholly owned subsidiary of a publicly traded Canadian limited partnership (Corridor Pipeline) to provide materials transportation capabilities among the Muskeg River mine, the Scotford upgrader and markets in Edmonton. The contract, originally signed in 1999 by a company we acquired, allows each holder of an undivided interest in the AOSP to ship materials in accordance with its undivided interest. Costs under this contract are accrued and recorded on a monthly basis, with a $3 million current liability recorded at December 31, 2011. Under this agreement, the AOSP absorbs all of the operating and

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capital costs of the pipeline. Currently, no third-party shippers use the pipeline. Should shipments be suspended, by choice or due to force majeure, we remain responsible for the portion of the payments related to our undivided interest for all remaining periods. The contract expires in 2029; however, the shippers can extend its term perpetually. This contract qualifies as a variable interest contractual arrangement and the Corridor Pipeline qualifies as a variable interest entity (VIE). We hold a variable interest but are not the primary beneficiary because our shipments are only 20 percent of the total; therefore the Corridor Pipeline is not consolidated. Our maximum exposure to loss as a result of our involvement with this VIE is the amount we expect to pay over the contract term, which was $715 million as of December 31, 2011. The liability on our books related to this contract at any given time will reflect amounts due for the immediately previous month s activity, which is substantially less than the maximum exposure over the contract term. We have not provided financial assistance to Corridor Pipeline and we do not have any guarantees of such assistance in the future.

5. Acquisitions

During the fourth quarter of 2011, we closed a series of transactions in the Eagle Ford shale formation in south Texas that were accounted for as a business combination. The most significant of these transactions was the acquisition of Hilcorp Resources, LLC. The total consideration paid for all the transactions including approximately 167,000 net acres and a gathering system, was $4.5 billion which was funded from existing cash. All Eagle Ford properties are included in our E&P segment.

The following table summarizes the amounts allocated to the assets acquired and liabilities assumed based upon their fair values at the acquisition dates:

(In millions)		
Current assets:		
Receivables	$	40
Inventories		4
Other current assets		30
Total current assets acquired		74
Property, plant and equipment		4,501
Other noncurrent assets		21
Total assets acquired	$	4,596
Current liabilities:		
Accounts payable	$	101
Other current liabilities		20
Total current liabilities assumed		121
Asset retirement obligations		5
Total liabilities assumed		126
Net assets acquired	$	4,470

The fair values of assets acquired and liabilities assumed were measured primarily using an income approach, specifically utilizing a discounted cash flow analysis. The estimated fair values were based on significant inputs not observable in the market, and therefore represent Level 3 measurements. Significant inputs included estimated reserve volumes, the expected future production profile, estimated commodity prices and assumptions regarding future operating and development costs. A discount rate of approximately 11 percent was used in the discounted cash flow analysis. The accounting for this transaction is complete.

The pro forma impact of this business combination is not material to our consolidated statement of income for 2011 and 2010.

In addition, during 2011, we acquired approximately 108,000 net acres in the Eagle Ford shale for approximately $265 million. These transactions were funded from existing cash and were accounted for as asset acquisitions.

6. Dispositions

2012 pipelines In October 2011, we entered into definitive agreements to sell our E&P segment s interests in several Gulf of Mexico crude oil pipeline systems. This includes our equity method interests in Poseidon Oil Pipeline

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Company, L.L.C. and Odyssey Pipeline L.L.C., as well as certain other oil pipeline interests, including the Eugene Island pipeline system. The value of this transaction is approximately $205 million, net of debt assumed by the buyer. The carrying value of these assets was $38 million as of December 31, 2011. This transaction closed on January 3, 2012.

2011

Burns Point gas plant During the fourth quarter of 2011, we sold our E&P segment s 50 percent interest in the Burns Point gas plant, a cryogenic processing plant located in St. Mary Parish, Louisiana, for total consideration of $36 million and a pretax gain of $34 million was booked.

Alaska LNG facility During the third quarter of 2011, we sold our Integrated Gas segment s equity interest in a LNG processing facility in Alaska and a pretax gain on the transaction of $8 million was recorded.

DJ Basin In April 2011, we assigned a 30 percent undivided working interest in our E&P segment s approximately 180,000 acres in the Niobrara shale play located within the DJ Basin of southeast Wyoming and northern Colorado for total consideration of $270 million, recording a pretax gain of $37 million. We remain operator of this jointly owned leasehold.

2010

Angola During 2010, we closed the sale of a 20 percent outside-operated interest in our E&P segment s Production Sharing Contract and Joint Operating Agreement in Block 32 offshore Angola. We received net proceeds of $1.3 billion and recorded a pretax gain on the sale of $811 million. We retained a 10 percent outside-operated interest in Block 32.

Gudrun In March 2011, we closed the sale of our outside-operated interests in the Gudrun field development and the Brynhild and Eirin exploration areas offshore Norway for net proceeds of $85 million, excluding working capital adjustments. A $64 million pretax loss on this disposition was recorded in the fourth quarter 2010.

2009

Gabon In December 2009, we closed the sale of our operated fields offshore Gabon, receiving net proceeds of $269 million, after closing adjustments. A $232 million pretax gain on this disposition was reported in discontinued operations for 2009.

Permian Basin In June 2009, we closed the sale of our E&P segment s operated and a portion of our outside-operated Permian Basin producing assets in New Mexico and west Texas for net proceeds after closing adjustments of $293 million. A $196 million pretax gain on the sale was recorded.

Ireland In April 2009, we closed the sale of our operated properties in Ireland for net proceeds of $84 million, after adjusting for cash held by the sold subsidiary. A $158 million pretax gain on the sale was recorded. As a result of this sale, we terminated our pension plan in Ireland, incurring a charge of $18 million.

In June 2009, we entered into an agreement to sell the subsidiary holding our 19 percent outside-operated interest in the Corrib natural gas development offshore Ireland. An initial $100 million payment was received at closing. Additional fixed proceeds of $135 million will be received at the earlier of first commercial gas or December 31, 2012. A $154 million impairment was recognized in discontinued operations in the second quarter of 2009.

Our Irish and our Gabonese businesses, which had been reported in our E&P segment, have been reported as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows. Revenues and pretax income related to these businesses are shown in the table below.

(In millions)		2009
Revenues applicable to discontinued operations	$	188
Pretax income from discontinued operations	$	80

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7. Income per Common Share

Basic income per share is based on the weighted average number of common shares outstanding, including securities exchangeable into common shares. Diluted income per share assumes exercise of stock options and stock appreciation rights, provided the effect is not antidilutive.

	2011		2010		2009	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 1,707	$ 1,707	$ 1,882	$ 1,882	$ 716	$ 716
Discontinued operations	1,239	1,239	686	686	747	747
Net income	$ 2,946	$ 2,946	$ 2,568	$ 2,568	$ 1,463	$ 1,463
Weighted average common shares outstanding	710	710	710	710	709	709
Effect of dilutive securities	-	4	-	2	-	2
Weighted average common shares, including dilutive effect	710	714	710	712	709	711
Per share:						
Income from continuing operations	$ 2.40	$ 2.39	$ 2.65	$ 2.65	$ 1.01	$ 1.01
Discontinued operations	$ 1.75	$ 1.74	$ 0.97	$ 0.96	$ 1.05	$ 1.05
Net income	$ 4.15	$ 4.13	$ 3.62	$ 3.61	$ 2.06	$ 2.06

The per share calculations above exclude 7 million, 13 million and 10 million stock options and stock appreciation rights in 2011, 2010 and 2009 that were antidilutive.

8. Segment Information

We have three reportable operating segments: Exploration and Production; Oil Sands Mining; and Integrated Gas. Each of these segments is organized and managed based upon the nature of the products and services they offer.

E&P explores for, produces and markets liquid hydrocarbons and natural gas on a worldwide basis.

OSM mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

IG produces and markets products manufactured from natural gas, such as LNG and methanol, in EG.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker (CODM). Segment income represents income from continuing operations, net of income taxes, attributable to the operating segments. Our corporate general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate activities, net of associated income tax effects. Foreign currency remeasurement and transaction gains or losses are not allocated to operating segments. Non-cash gains and losses on two natural gas sales contracts in the United Kingdom that were accounted for as derivative instruments, impairments, gains or losses on disposal of assets or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.

As discussed in Note 3, our downstream business was spun-off on June 30, 2011 and has been reported as discontinued operations in all periods presented. Sales to MPC previously reported as Intersegment revenues are now reported as Customer revenues because such sales are expected to continue subsequent to the spin-off. Such sales were $1.4 billion in the first six months of 2011, $1.8 billion in 2010 and $534 million in 2009.

In 2011 and 2010, MPC accounted for approximately 18 percent and 16 percent of total revenues. In 2010 and 2009, the Libyan National Oil Company accounted for approximately 13 percent and 13 percent of total revenues.

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Differences between segment totals for income from equity method investments, taxes and depreciation, depletion and amortization and our consolidated totals represent amounts related to corporate administrative activities and other unallocated items and are included in Items not allocated to segments, net of income taxes in the reconciliation below. Capital expenditures include accruals but not corporate administrative activities. As discussed in Notes 3 and 6, discontinued operations for our downstream business in all periods and our Irish and Gabonese businesses in 2009 have been excluded from segment results.

(In millions)	E&P	OSM	IG	Total
2011				
Revenues:				
Customer	$ 12,922	$ 1,588	$ 93	$ 14,603
Intersegment	47	-	-	47
Related parties	60	-	-	60
Segment revenues	13,029	1,588	93	14,710
Elimination of intersegment revenues	(47)	-	-	(47)
Total revenues	$ 12,982	$ 1,588	$ 93	$ 14,663
Segment income	$ 2,157	$ 256	$ 178	$ 2,591
Income from equity method investments	249	-	213	462
Depreciation, depletion and amortization	2,028	196	3	2,227
Income tax provision	2,808	82	74	2,964
Capital expenditures	3,038	308	2	3,348

(In millions)	E&P	OSM	IG	Total
2010				
Revenues:				
Customer	$ 10,651	$ 833	$ 150	$ 11,634
Intersegment	75	-	-	75
Related parties	56	-	-	56
Segment revenues	10,782	833	150	11,765
Elimination of intersegment revenues	(75)	-	-	(75)
Total revenues	$ 10,707	$ 833	$ 150	$ 11,690
Segment income (loss)	$ 1,941	$ (50)	$ 142	$ 2,033
Income from equity method investments	188	-	181	369
Depreciation, depletion and amortization	1,911	105	2	2,018
Income tax provision (benefit)	2,266	(12)	73	2,327
Capital expenditures	2,474	874	2	3,350

(In millions)	E&P	OSM	IG	Total
2009				
Revenues:				
Customer	$ 7,651	$ 692	$ 50	$ 8,393

Intersegment	28	-	-	28
Related parties	59	-	-	59
Segment revenues	7,738	692	50	8,480
Elimination of intersegment revenues	(28)	-	-	(28)
Gain on U.K. natural gas contracts[(a)]	72	-	-	72 [(a)]
Total revenues	$ 7,782	$ 692	$ 50	$ 8,524
Segment income	$ 1,218	$ 44	$ 90	$ 1,352
Income from equity method investments	125	-	143	268
Depreciation, depletion and amortization	1,776	124	3	1,903
Income tax provision	1,560	6	39	1,605
Capital expenditures	2,162	1,115	2	3,279

(a) The U.K. natural gas contracts expired in September 2009.

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The following reconciles segment income to net income as reported in the consolidated statements of income.

(In millions)	2011	2010	2009
Segment income	$ 2,591	$ 2,033	$ 1,352
Items not allocated to segments, net of income taxes:			
Corporate and other unallocated items	(326)	(202)	(431)
Foreign currency remeasurement of taxes	9	32	(319)
Impairments[a]	(195)	(286)	(45)
Loss on early extinguishment of debt	(176)	(57)	-
Tax effect of subsidiary restructuring	(122)	-	-
Deferred income taxes	(61)	(45)	-
Water abatement Oil Sands	(48)	-	-
Eagle Ford transaction costs	(10)	-	-
Gain on dispositions[b]	45	407	122
Gain on U.K. natural gas contracts	-	-	37
Income from continuing operations	1,707	1,882	716
Discontinued operations	1,239	686	747
Net income	$ 2,946	$ 2,568	$ 1,463

(a) Significant impairments are further discussed, on a pretax basis, in Note 15.

(b) Significant dispositions are further discussed, on a pretax basis, in Note 6.

The following reconciles total revenues to sales and other operating revenues reported in continuing operations in the consolidated statements of income.

(In millions)	2011	2010	2009
Total revenues	$ 14,663	$ 11,690	$ 8,524
Less: Sales to related parties	60	56	59
Sales and other operating revenues	$ 14,603	$ 11,634	$ 8,465

Revenues from external customers are attributed to geographic areas based upon selling location. The following summarizes revenues from external customers reported in continuing operations by geographic area.

(In millions)	2011	2010	2009
United States	$ 6,971	$ 5,363	$ 3,326
United Kingdom	1,546	1,063	1,143
Libya[(a)]	216	1,473	1,139
Norway	3,386	2,243	1,617

Canada	1,588	833	692
Other international	956	715	607
Total revenues	$ 14,663	$ 11,690	$ 8,524

(a) See Note 13 for discussion of Libya operations.

The following summarizes certain long-lived assets by geographic area, including property, plant and equipment and equity investments.

(In millions)	2011	2010
United States	$ 10,928	$ 18,415
Canada	9,711	9,564
Equatorial Guinea	2,214	2,389
Norway	1,133	1,353
Other international	2,721	2,399
Total long-lived assets	$ 26,707	$ 34,120

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Revenues by product line were:

(In millions)	2011	2010	2009
Liquid hydrocarbons	$ 13,298	$ 10,312	$ 7,343
Natural gas	1,291	1,295	1,126
Transportation & other	74	83	55
Total revenues	$ 14,663	$ 11,690	$ 8,524

9. Other Items

Net interest and other, related to continuing operations

(In millions)	2011	2010	2009
Interest:			
Interest income	$ 12	$ 11	$ 8
Interest expense[a]	(281)	(375)	(262)
Income on interest rate swaps	10	26	17
Interest capitalized	151	297	214
Total interest	(108)	(41)	(23)
Other:			
Net foreign currency gains (losses)	24	(21)	(28)
Write-off of contingent proceeds[b]	(7)	(15)	(70)
Other	(16)	2	(1)
Total other	1	(34)	(99)
Net interest and other	$ (107)	$ (75)	$ (122)

[a] Excludes $10 million, $16 million and $27 million paid by United States Steel in 2011, 2010 and 2009 on assumed debt.

[b] A portion of the contingent proceeds from the sale of the Corrib natural gas development was written off in the fourth quarter of 2009 on the basis of new public information regarding the pipeline that would transport gas from the Corrib development. The remaining carrying value of this contingent receivable was written off in 2010.

Foreign currency transactions Aggregate foreign currency gains (losses) related to continuing operations were included in the consolidated statements of income as follows:

(In millions)	2011	2010	2009
Net interest and other	$ 24	$ (21)	$ (28)
Provision for income taxes	(57)	(1)	(319)
Aggregate foreign currency losses	$ (33)	$ (22)	$ (347)

10. Income Taxes

Income tax provisions (benefits) related to continuing operations were:

	2011			2010			2009		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ (210)	$ (206)	$ (416)	$ (279)	$ (267)	$ (546)	$ 40	$ (329)	$ (289)
State and local	24	82	106	2	(10)	(8)	(19)	5	(14)
Foreign	3,088	(58)	3,030	2,941	(212)	2,729	1,480	870	2,350
Total	$ 2,902	$ (182)	$ 2,720	$ 2,664	$ (489)	$ 2,175	$ 1,501	$ 546	$ 2,047

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A reconciliation of the federal statutory income tax rate applied to income from continuing operations before income taxes to the provision for income taxes follows:

	2011	2010	2009
Statutory rate applied to income from continuing operations before income taxes	35%	35%	35%
Effects of foreign operations, including foreign tax credits	6	20	16
Change in permanent reinvestment assertion	5	-	-
Foreign currency remeasurement	-	-	11
Adjustments to valuation allowances	14	(2)	10
Tax law changes	1	1	-
Other	-	-	2
Effective income tax rate on continuing operations	61%	54%	74%

Effects of foreign operations The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments and to individual items not allocated to segments is reported in Corporate and other unallocated items shown in Note 8.

The effects of foreign operations on our effective tax rate decreased in 2011 as compared to 2010, primarily due to the suspension of all production operations in Libya in the first quarter of 2011, where the statutory tax rate is in excess of 90 percent.

Change in permanent reinvestment assertion In the second quarter of 2011, we recorded $716 million of deferred U.S. tax on undistributed earnings of $2,046 million that we previously intended to permanently reinvest in foreign operations. Offsetting this tax expense were associated foreign tax credits of $488 million. In addition, we reduced our valuation allowance related to foreign tax credits by $228 million due to recognizing deferred U.S. tax on previously undistributed earnings.

Adjustments to valuation allowances In 2009, it was determined that we may not be able to realize all recorded foreign tax credit benefits and therefore a valuation allowance was recorded against these benefits. In 2011, we increased the valuation allowance against foreign tax credits because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in 2011.

Tax law changes In July 2011, the U.K. enacted the Finance Bill 2011 which increased the rate of the supplementary charge levied on profits from U.K. oil and gas production from 20 percent to 32 percent. As a result of this legislation, we recorded deferred tax expense of $10 million in 2011.

On May 25, 2011, Michigan enacted legislation that replaced the Michigan Business Tax (MBT) with a corporate income tax (CIT), effective January 1, 2012. The new CIT legislation eliminates the book-tax difference deduction that was provided under the MBT to mitigate the net increase in a taxpayer s deferred tax liability resulting when Michigan moved from the Single Business Tax, a non-income tax, to the MBT, an income tax, on July 12, 2007. Such a change in the tax law must be recognized in earnings in the period enacted regardless of the effective date. The total effect of tax law changes on deferred tax balances is recorded as income tax expense related to continuing operations in the period the law is enacted, even if a portion of the deferred tax balances relates to discontinued operations. As a result of the new CIT legislation, we recorded deferred tax expense of $32 million in the second quarter of 2011.

The Patient Protection and Affordable Care Act (PPACA) and the Health Care and Education Reconciliation Act of 2010 (HCERA), (together, the Acts) were signed in to law in March 2010. The Acts effectively change the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under

Medicare Part D. The federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the MPDIMA). Under the MPDIMA, the federal subsidy does not reduce our income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually. Beginning in 2013, under the Acts, our income tax deduction for the costs of providing Medicare Part D-equivalent prescription drug benefits to retirees will be reduced by the amount of the federal subsidy. Such a change in the tax law must be recognized in earnings in the period enacted regardless of the effective date. The total effect of tax law changes on deferred tax balances is recorded as income tax expense related to continuing operations in the period the law is enacted, even if a portion of the deferred tax balances relates to discontinued operations. As a result, we recorded deferred tax expense of $45 million in the first quarter of 2010 for the write-off of deferred tax assets to reflect the change in the tax treatment of the federal subsidy.

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Deferred tax assets and liabilities resulted from the following:

(In millions)	December 31, 2011	2010
Deferred tax assets:		
Employee benefits	$ 413	$ 1,079
Operating loss carryforwards[a]	376	285
Foreign tax credits	3,005	2,045
Other	88	141
Valuation allowances		
Federal	(791)	(206)
State	(61)	(48)
Foreign[a]	(194)	(142)
Total deferred tax assets	2,836	3,154
Deferred tax liabilities		
Property, plant and equipment[a]	3,283	5,292
Inventories	-	597
Investments in subsidiaries and affiliates	1,286	1,116
Other	43	42
Total deferred tax liabilities	4,612	7,047
Net deferred tax liabilities	$ 1,776	$ 3,893

[a] Certain 2010 amounts were reclassified to conform to the current period s presentation.

Operating loss carryforwards At December 31, 2011, our operating loss carryforwards include $811 million of Canadian operating loss carryforwards that expire from 2013 through 2031 and $245 million of Indonesian operating loss carryforwards that do not have expiration dates. State operating loss carryforwards of $915 million expire in 2012 through 2031.

Valuation allowances The ability to realize the benefit of foreign tax credits is based on certain estimates concerning future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and our tax profile in the years that such credits may be claimed. Federal valuation allowances increased $585 million in 2011, decreased $74 million in 2010 and increased $280 million in 2009 due to changes in the expected realizability of foreign tax credits.

Foreign valuation allowances increased $52 million and $40 million in 2011 and 2010, primarily due to net operating loss carryforwards generated in Indonesia. Foreign valuation allowances decreased $79 million in 2009, primarily due to the reduction of net operating loss carryforwards as a result of the disposition of exploration and production businesses in Ireland.

Net deferred tax liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
(In millions)	2011	2010
Assets:		
Current deferred tax assets	$ 99	$ -
Other noncurrent assets	674	-
Liabilities:		
Current deferred tax liabilities	5	324
Noncurrent deferred tax liabilities	2,544	3,569
Net deferred tax liabilities	$ 1,776	$ 3,893

We are continuously undergoing examination of our U.S. federal income tax returns by the Internal Revenue Service. Such audits have been completed through the 2007 tax year. We believe adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities.

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As of December 31, 2011, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[(a)]	2004	2010
Canada	2006	2010
Equatorial Guinea	2006	2010
Libya	2006	2009
Norway	2008	2010
United Kingdom	2008	2010

(a) Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2011	2010	2009
Beginning balance	$ 103	$ 75	$ 39
Additions for tax positions related to the current year	4	28	30
Reductions for tax positions related to the current year	-	(1)	(2)
Additions for tax positions of prior years	87	25	30
Reductions for tax positions of prior years	(29)	(12)	(15)
Settlements	(8)	(12)	(7)
Ending balance	$ 157	$ 103	$ 75

If the unrecognized tax benefits as of December 31, 2011 were recognized, $103 million would affect our effective income tax rate. There were $19 million of uncertain tax positions as of December 31, 2011 for which it is reasonably possible that the amount of unrecognized tax benefits would significantly increase or decrease during the next twelve months.

Interest and penalties are recorded as part of the tax provision, and related to unrecognized tax benefits were $13 million, $5 million and less than $1 million in 2011, 2010 and 2009. As of December 31, 2011 and 2010, $27 million and $15 million of interest and penalties were accrued related to income taxes.

Pretax income from continuing operations included amounts attributable to foreign sources of $4,869 million, $4,563 million and $2,947 million in 2011, 2010 and 2009.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2011 amounted to $235 million for which no U.S. deferred income tax provision has been recorded because we intend to permanently reinvest such income in those foreign operations. If such income was not permanently reinvested, income tax expense of approximately $82 million would be recorded, not including potential utilization of foreign tax credits.

11. Inventories

Inventories are carried at the lower of cost or market value. A significant portion of our inventories at December 31, 2010 were related to our downstream business (see Note 3).

(In millions)	December 31, 2011	2010
Liquid hydrocarbons, natural gas and bitumen	$ 147	$ 1,275
Refined products and merchandise	-	1,774
Supplies and sundry items	214	404
Inventories at cost	$ 361	$ 3,453

The LIFO method accounted for 16 percent and 85 percent of total inventory value at December 31, 2011 and 2010. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2011 and 2010 by $74 million and $4,166 million.

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12. Equity Method Investments and Related Party Transactions
During 2011, 2010 and 2009 only our equity method investees were considered related parties. The following were included in continuing operations:

Alba Plant LLC, in which we have a 52 percent noncontrolling interest. Alba Plant LLC processes LPG.

AMPCO, in which we have a 45 percent interest. AMPCO is engaged in methanol production activity.

EGHoldings, in which we have a 60 percent noncontrolling interest. EGHoldings is engaged in LNG production activities.
Our equity method investments are summarized in the following table:

	Ownership as of	December 31,	
(In millions)	December 31, 2011	2011	2010
EGHoldings	60%	$ 875	$ 927
Alba Plant LLC	52%	272	303
AMPCO	45%	191	210
Downstream business investments		-	311
Other investments		45	51
Total		$ 1,383	$ 1,802

As of December 31, 2011, the carrying value of our equity method investments was $155 million higher than the underlying net assets of investees. This basis difference is being amortized into net income over the remaining estimated useful lives of the underlying net assets.

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) reported in continuing operations were $509 million in 2011, $400 million in 2010 and $302 million in 2009.

Summarized financial information for equity method investees is as follows:

(In millions)	2011[(a)]	2010	2009
Income data year:			
Revenues and other income	$ 1,544	$ 2,243	$ 1,916
Income from operations	942	999	677
Net income	820	841	576
Balance sheet data December 31:			
Current assets	$ 688	$ 898	
Noncurrent assets	2,079	3,371	
Current liabilities	504	513	
Noncurrent liabilities	115	832	

(a) Values in 2011 are lower than in previous years due to the spin-off of our downstream business on June 30, 2011.

Almost all of our related party purchases are liquid hydrocarbons acquired from Alba Plant LLC. Approximately 75 percent of our sales to related parties in all periods are associated with sales of natural gas to EGHoldings.

13. Property, Plant and Equipment

	December 31,	
(In millions)	2011	2010
E&P		
United States	$ 19,679	$ 13,532
International	12,579	11,736
Total E&P	32,258	25,268
OSM	9,936	9,631
IG	37	47
Downstream business	-	16,624
Corporate	341	457
Total property, plant and equipment	$ 42,572	$ 52,027
Less accumulated depreciation, depletion and amortization	(17,248)	(19,805)
Net property, plant and equipment	$ 25,324	$ 32,222

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During the first quarter 2011, all production operations in Libya were suspended. In the fourth quarter of 2011, limited production resumed from the Waha concessions, but we made no deliveries of hydrocarbons. Sales are expected in the first quarter of 2012. The return of our operations in Libya to pre-conflict levels is unknown at this time; however, we and our partners in the Waha concession are assessing the condition of our assets and determining when the full resumption of operations will be viable. As of December 31, 2011, our net property, plant and equipment investment in Libya is approximately $756 million and our net proved reserves in Libya are 239 mmboe.

Property, plant and equipment includes gross assets acquired under capital leases of $13 million and $272 million at December 31, 2011 and 2010, with related amounts in accumulated depreciation, depletion and amortization of $1 million and $48 million at December 31, 2011 and 2010.

Deferred exploratory well costs were as follows:

	December 31,		
(In millions)	2011	2010	2009
Amounts capitalized less than one year after completion of drilling	$ 482	$ 334	$ 679
Amounts capitalized greater than one year after completion of drilling	222	323	150
Total deferred exploratory well costs	$ 704	$ 657	$ 829
Number of projects with costs capitalized greater than one year after completion of drilling	5	7	3

(In millions)	2011	2010	2009
Beginning balance	$ 657	$ 829	$ 917
Additions	670	329	155
Dry well expense	(268)	(83)	(32)
Transfers to development	(279)	(54)	(211)
Dispositions	(76)	(364)	-
Ending balance	$ 704	$ 657	$ 829

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2011 are summarized by geographical area below:

(In millions)	
Gulf of Mexico	$ 73
Angola	124
Other International	25
Total	$ 222

Well costs that have been suspended for longer than one year are associated with five projects. Exploration on Angola Block 31 began in 2004, with costs accumulating through 2009. Development alternatives are being evaluated and optimization efforts continue for this block. Costs for two offshore Gulf of Mexico projects were incurred in 2009 and 2010. Drilling is expected to resume on the Innsbruck prospect in the second half of 2012, while evaluation of the outside-operated Shenandoah prospect is ongoing with an appraisal well expected in 2012. Two international projects had costs incurred in 2004 and 2009 and have the potential to tie-back to current production facilities. Development will be pursued when the additional production is required to feed our Equatorial Guinea and Norway operations. Management believes these projects with suspended exploratory drilling costs exhibit sufficient quantities of hydrocarbons to justify potential development.

14. Goodwill

Goodwill is tested for impairment on an annual basis, or when events or changes in circumstances indicate the fair value of a reporting unit with goodwill has been reduced below the carrying value. We performed our annual impairment tests during 2011, 2010 and 2009 and no impairment was required. The fair value of each of our reporting units exceeded the book value appreciably; however, should market conditions deteriorate or commodity prices decline significantly, an impairment may be necessary.

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The changes in the carrying amount of goodwill for the years ended December 31, 2011, and 2010 were as follows:

(In millions)	E&P	OSM	Downstream business	Total
2010				
Beginning balance, gross	$ 537	$ 1,412	$ 885	$ 2,834
Less: accumulated impairment	-	(1,412)	-	(1,412)
Beginning balance, net	537	-	885	1,422
Contingent consideration adjustment	-	-	(1)	(1)
Purchase price adjustment	-	-	(7)	(7)
Dispositions	-	-	(34)	(34)
Ending balance, net	537	-	843	1,380
2011				
Beginning balance, gross	537	1,412	843	2,792
Less: accumulated impairments	-	(1,412)	-	(1,412)
Beginning balance, net	537	-	843	1,380
Dispositions	(1)	-	(2)	(3)
Contingent consideration adjustment	-	-	(3)	(3)
Purchase price adjustment	-	-	9	9
Spin-off downstream business	-	-	(847)	(847)
Ending balance, net	$ 536	$ -	$ -	$ 536

15. Fair Value Measurements

Fair Values Recurring

As of December 31, 2011, balances related to interest rate swaps accounted for at fair value on a recurring basis were noncurrent assets of $5 million measured at fair value using actionable broker quotes which are Level 2 inputs. There were no other significant recurring fair value measurements as of December 31, 2011.

The following table presents assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2010 by fair value hierarchy level. The majority of commodity derivatives outstanding at December 31, 2010 related to our downstream business.

	December 31, 2010				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$ 58	$ -	$ 1	$ 81	$ 140
Interest rate	-	32	-	-	32

Derivative instruments, assets		58		32		1		81		172
Derivative instruments, liabilities										
Commodity	$	(102)	$	-	$	(3)	$	-	$	(105)
Derivative instruments, liabilities		(102)		-		(3)		-		(105)

As of December 31, 2010, commodity derivatives in Level 1 were exchange-traded contracts for crude oil, natural gas and refined products measured at fair value with a market approach using the close-of-day settlement prices for the market. Interest rate swaps were in Level 2 of the fair value hierarchy because they were measured at fair value with a market approach using market price quotes or a price obtained from third-party services such as Bloomberg L.P. which were corroborated with data from active markets for similar assets and liabilities. Collateral deposits related to commodity derivatives are in broker accounts covered by master netting agreements.

Commodity derivatives in Level 3 are measured at fair value with a market approach using prices obtained from third-party services such as Platt s and price assessments from other independent brokers.

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The following is a reconciliation of the net beginning and ending balances recorded for derivative instruments classified as Level 3 in the fair value hierarchy.

(In millions)	2011	2010	2009
Beginning balance	$ (2)	$ 9	$ (26)
Total realized and unrealized gains (losses):			
Included in net income	-	23	68
Included in other comprehensive income	-	4	(1)
Transfers to Level 2	-	(30)	-
Purchases	-	2	5
Sales	-	-	(23)
Issuances	-	-	(44)
Settlements	-	(10)	30
Spin-off of downstream business	2	-	-
Ending balance	$ -	$ (2)	$ 9

Net income for 2010 and 2009 included unrealized losses of $1 million, and $7 million related to the derivatives in Level 3. See Note 16 for income statement impacts of our derivative instruments.

Fair Values Nonrecurring

The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition for continuing operations.

	2011		2010		2009	
(In millions)	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 226	$ 282	$ 147	$ 447	$ 5	$ 15
Long-lived assets held for sale	-	-	85	64	311	154
Intangible assets	-	25	-	-	-	-
Equity method investments	-	-	-	25	-	-

In May 2011, significant water production and reservoir pressure declines occurred at our E&P segment s Droshky development in the Gulf of Mexico. Plans for a waterflood were cancelled and the field will be produced to abandonment pressures, which are expected in the first half of 2012. Consequently, 3.4 million barrels of oil equivalent of proved reserves were written off and a $273 million impairment of this long-lived asset to fair value was recorded in the second quarter of 2011. The $226 million fair value of the Droshky development was determined using an income approach based upon internal estimates of future production levels, prices and discount rate, all Level 3 inputs.

In the second quarter of 2011, our outlook for U.S. natural gas prices made it unlikely that sufficient U.S. demand for LNG would materialize by 2021, which is when the rights lapse under our arrangements at the Elba Island, Georgia regasification facility. Using an income approach based upon internal estimates of gas prices and future deliveries, which are Level 3 inputs, we determined that the contract had no remaining fair value and recorded a full impairment of this intangible asset held in our Integrated Gas segment.

In the fourth quarter of 2010, due to the pending sale of our E&P segment s outside-operated interest in the Gudrun field development, located offshore Norway, we recorded a loss for this asset held for sale. The fair value of $85 million was based upon the pending transaction, which is a

Level 3 market input.

In the third quarter of 2010, we fully impaired our Integrated Gas segment s equity method investment in an entity engaged in gas-to-fuels related technology. This investment was determined to have sustained an other than temporary loss in value. Based upon recent financial information, the fair value was measured with an income approach using internally developed estimates of future cash flows. These cash flows are Level 3 inputs.

In March 2010, we completed a reservoir study which resulted in a portion of our Powder River Basin field being removed from plans for future development in our E&P segment. The field s fair value was measured at $144 million, using an income approach based upon internal estimates of future production levels, prices and discount rate which are Level 3 inputs. This resulted in an impairment of $423 million.

The impairment charge recorded on assets held for sale in 2009 related to the sale of the Corrib natural gas development offshore Ireland and was based on the fair value of anticipated sale proceeds (see Note 6). Fair value of

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anticipated sale proceeds included cash received at closing, a minimum amount due at the earlier of first gas or December 31, 2012, and a range of contingent proceeds subject to the timing of first commercial gas. The fair value of the total proceeds was measured using an income method that incorporated a probability-weighted approach with respect to timing of first commercial gas and an associated sliding scale on the amount of corresponding consideration specified in the sales agreement: the longer it takes to achieve first gas, the lower the amount of the consideration. Because a portion of the proceeds is variable in timing and amount depending upon timing of first commercial gas, the inputs to the fair value calculation were classified as Level 3 inputs.

Impairments of several other long-lived assets held for use in our E&P segment that were evaluated in 2011, 2010 and 2009 were a result of reduced drilling expectations, reduction of estimated reserves or declining natural gas prices, and are also reported above. The fair values of those assets were measured using an income approach based upon internal estimates of future production levels, commodity prices and discount rate, which are Level 3 inputs. Natural gas prices began declining in September 2011 and have continued to decline in 2012. Should natural gas prices remain depressed, an impairment charge related to our natural gas assets may be necessary.

Fair Values Financial Instruments

The following table summarizes financial instruments, excluding the derivative financial instruments reported above, by individual balance sheet line item at December 31, 2011 and 2010.

	December 31,			
	2011[(a)]		2010	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other current assets	$ 146	$ 148	$ 226	$ 220
Other noncurrent assets	68	68	396	231
Total financial assets	214	216	622	451
Financial liabilities				
Long-term debt, including current portion[(b)]	5,479	4,753	8,364	7,527
Deferred credits and other liabilities	36	38	66	67
Total financial liabilities	$ 5,515	$ 4,791	$ 8,430	$ 7,594

(a) Financial assets and liabilities have decreased from 2010 due to the spin-off of our downsteam business, early retirement of long-term debt and United States Steel s redemption of the bonds for which they retained responsibilty.

(b) Excludes capital leases.

Our current assets and liabilities include financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of these current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our investment-grade credit rating, and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk. The current portion of our long-term debt, which is reported with long-term debt above and discussed below, is an exception to this assessment.

Fair values of our remaining financial assets included in other noncurrent assets and of our financial liabilities included in deferred credits and other liabilities are measured using an income approach and most inputs are internally generated, which results in a Level 3 classification. Estimated future cash flows are discounted using a rate deemed appropriate to obtain the fair value.

Over 90 percent of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions is used to measure the fair value of such debt. Because such quotes cannot be independently verified to the market they are considered Level 3 inputs. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

16. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 15. See Note 1 for discussion of the types of derivatives we use and the reasons for them. As of December 30, 2011, our only derivatives outstanding are interest rate swaps that are fair value hedges, which have an asset value of $5 million and are located on the consolidated balance sheet in Other noncurrent assets.

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The following table presents the gross fair values of derivative instruments, excluding cash collateral, and where they appear on the consolidated balance sheet as of December 31, 2010. The majority of our 2010 commodity derivatives were related to our downstream business.

	December 31, 2010			
(In millions)	Asset	Liability	**Net Asset**	Balance Sheet Location
Fair Value Hedges				
Interest rate	$ 32	$ -	$ 32	Other noncurrent assets
Total Designated Hedges	32	-	32	
Not Designated as Hedges				
Commodity	58	102	(44)	Other current assets
Total Not Designated as Hedges	58	102	(44)	
Total	$ 90	$ 102	$ (12)	

	December 31, 2010			
(In millions)	Asset	Liability	**Net Liability**	Balance Sheet Location
Not Designated as Hedges				
Commodity	$ 1	$ 3	$ 2	Other current liabilities
Total Not Designated as Hedges	1	3	2	
Total	$ 1	$ 3	$ 2	

Derivatives Designated as Cash Flow Hedges

We had no derivatives designated as cash flow hedges at December 31, 2011 and 2010.

The following table summarizes the pretax effect of derivative instruments designated as cash flow hedges in other comprehensive income:

	Gain (Loss) in OCI		
(In millions)	2011	2010	2009
Foreign currency	$ -	$ 4	$ 39
Interest rate	$ -	$ -	$ (15)

Derivatives Designated as Fair Value Hedges

As of December 31, 2011, we had multiple interest rate swap agreements with a total notional amount of $600 million at a weighted-average, LIBOR-based, floating rate of 4.76 percent. As of December 31, 2010, we had multiple interest rate swap agreements with a total notional amount of $1,450 million at a weighted-average, LIBOR-based, floating rate of 4.43 percent. The interest rate swaps have no hedge ineffectiveness.

In connection with the debt retired in February and March 2011 discussed in Note 17, we settled interest rate swaps with a notional amount of $1,450 million. We recorded a $29 million gain, which reduced the loss on early extinguishment of debt.

The following table summarizes the pretax effect related to continuing operations of derivative instruments designated as hedges of fair value in our consolidated statements of income.

		Gain (Loss)		
(In millions)	Income Statement Location	2011	2010	2009
Derivative				
Commodity	Sales and other operating revenues	$ -	$ (1)	$ (16)
Interest rate	Net interest and other	28	26	-
		28	25	(16)
Hedged Item				
Commodity	Sales and other operating revenues	-	1	16
Long-term debt	Net interest and other	(28)	(26)	-
		$ (28)	$ (25)	$ 16

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MARATHON OIL CORPORATION

Notes to Consolidated Financial Statements

Derivatives Not Designated as Hedges

The following table summarizes the effect related to continuing operations of all derivative instruments not designated as hedges in our consolidated statements of income.

		Gain (Loss)		
(In millions)	Income Statement Location	2011	2010	2009
Commodity	Sales and other operating revenues	$ 5	$ 121	$ 90
Foreign currency	Net interest and other	-	-	3
		$ 5	$ 121	$ 93

17. Debt

As of December 31, 2011, we had no borrowings against our $3 billion revolving credit facility and no commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

	December 31,	
(In millions)	2011	2010
Marathon Oil Corporation:		
Revolving credit facility	$ -	$ -
6.125% notes due 2012	-	450
6.000% notes due 2012	-	400
5.900% notes due 2018[(a)]	854	894
6.800% notes due 2032[(a)]	550	550
9.375% debentures due 2012	53	53
9.125% debentures due 2013	114	114
6.500% debentures due 2014	-	700
7.500% debentures due 2019[(a)]	228	688
6.000% debentures due 2017[(a)]	682	