SECURITIES AND EXCHANGE COMMISSION

FORM 10-K

Annual report pursuant to section 13 and 15(d)

Filing Date: **2012-02-29** | Period of Report: **2011-12-31**
SEC Accession No. 0001193125-12-088742

FILER

MARATHON OIL CORP

CIK:**101778**| IRS No.: **250996816** | State of Incorp.:**DE** | Fiscal Year End: **1231**
Type: **10-K** | Act: **34** | File No.: **001-05153** | Film No.: **12652177**
SIC: **2911** Petroleum refining

Mailing Address
5555 SAN FELIPE ROAD
HOUSTON TX 77056

Business Address
P O BOX 3128
HOUSTON TX 77253-3128
7136296600

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 ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant' s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, 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 ☑ 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 ☑

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.

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 to 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).

Table of Contents

Table of Contents

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.

[Table of Contents](#)

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.

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," "forecast," "plan," "predict," "target," "project," "could," "may," "should," "would" or similar words, indicating that future outcomes are uncertain. In accordance with "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, 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.

[Table of Contents](#)

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.

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 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.

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.

Table of Contents

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.

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.

[Table of Contents](#)

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

December 31, 2009	North America United States	North America Canada	North America Total	Africa EG	Africa Other	Africa Total	Europe 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 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.

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.

[Table of Contents](#)

Average Sales Price per Unit

(Dollars per unit)	North America			Africa			Europe		
	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]

(Dollars per boe)	North America			Africa			Europe		
	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.

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 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.

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.

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.

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.

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.

Table of Contents

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 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.

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:

	Column (a)		Column (b)	Column (c)	Column (d)
Period	Total Number of Shares Purchased[(a)]		Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(c)]	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).

Table of Contents

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.

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 accordance with "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

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.

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

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 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.

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.

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 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, 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.

Table of Contents

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.

[Table of Contents](#)

Item 8. Financial Statements and Supplementary Data

Index

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 Chief Executive Officer	*Executive Vice President and Chief Financial Officer*	*Vice President, Finance and Accounting, Controller and Treasurer*

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 Chief Executive Officer	*Executive Vice President and Chief Financial Officer*

[Table of Contents](#)

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

Table of Contents

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.

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.

Table of Contents

MARATHON OIL CORPORATION
Consolidated Balance Sheets

(In millions, except per share data)	December 31, 2011	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.

Table of Contents

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.

Table of Contents

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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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 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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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 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

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	

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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

Deferred tax assets and liabilities resulted from the following:

	December 31,	
(In millions)	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.

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).

	December 31,	
(In millions)	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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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:

(In millions)	Ownership as of December 31, 2011	December 31, 2011	December 31, 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

(In millions)	December 31, 2011	December 31, 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

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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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 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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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

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	682
9.375% debentures due 2022	32	32
8.500% debentures due 2023	70	70
8.125% debentures due 2023	131	131
6.600% debentures due 2037	750	750
4.550% promissory note, semi-annual payments due 2012 – 2015	272	340
Series A medium term notes due 2022	3	3
4.750% – 6.875% obligations relating to industrial development and environmental improvement bonds and notes due 2013 – 2033	-	198
5.375% obligation relating to revenue bonds due 2013	23	23
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Sale-leaseback financing due 2012	11	20
Capital lease obligation due 2012	9	17
Consolidated subsidiaries		
8.375% secured notes due 2012[(a)]	-	448
Capital lease obligations due 2012 – 2034		
Downstream business	-	279
Other	11	12

Total[b]	4,793	7,854
Unamortized fair value differential for debt assumed in acquisitions	-	16
Unamortized discount	(10)	(16)
Fair value adjustments[c]	32	42
Amounts due within one year	(141)	(295)
Total long-term debt due after one year	$4,674	$7,601

(a) These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

(b) In the event of a change in control, as defined in the related agreements, debt obligations totaling $431 million at December 31, 2011, may be declared immediately due and payable.

(c) See Note 15 for information on interest rate swaps.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

The termination date on $2,625 million of our revolving credit facility is May 2013. The remaining $375 million has a termination date of May 2012. The facility requires a representation at an initial borrowing that there has been no change in our consolidated financial position or operations, considered as a whole which would materially and adversely affect our ability to perform our obligations under the revolving credit facility. Interest on the facility is based on defined short-term market rates. During the term of the agreement, we are obligated to pay a variable facility fee on the total commitment, which at December 31, 2011 was 0.10 percent.

Our long-term debt agreements do not contain restrictive financial covenants.

On December 31, 2010, we were obligated (primarily or contingently) for $221 million of debt for which United States Steel assumed responsibility for repayment. During the fourth quarter of 2011, United States Steel called all industrial development and environmental improvement bonds and notes for which they had assumed responsibility.

The following table shows five years of debt payments:

(In millions)	
2012	$ 141
2013	205
2014	68
2015	68
2016	-

In February and March 2011, we retired the following debt at a weighted average price equal to 112 percent of face value. A $279 million loss on early extinguishment of debt was recognized in the first quarter of 2011. The loss includes related deferred financing and premium costs partially offset by the gain on settled interest rate swaps.

(In millions)	
6.000% notes due 2012	$400
6.125% notes due 2012	450
8.375% secured notes due 2012[a]	448
6.500% debentures due 2014	700
5.900% notes due 2018	40
7.500% debentures due 2019	460
Total debt purchases	$ 2,498

(a) These notes were senior secured notes of Marathon Oil Canada Corporation.

In April 2010, we retired $500 million in aggregate principal of our debt under two tender offers at a weighted average price equal to 117 percent of face value. As a result, we recorded a loss on early extinguishment of debt of $92 million, including the transaction premium as well as the expensing of related deferred financing costs on the debt in the second quarter of 2010.

18. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)	2011	2010
Beginning balance	$1,355	$1,102
Incurred, including acquisitions	37	49
Settled	(39)	(28)
Accretion expense (included in depreciation, depletion and amortization)	81	70

Revisions to previous estimates	126	162
Spin-off downstream business	(50)	-
Ending balance[(a)]	$ 1,510	$ 1,355

(a) Includes asset retirement obligation of $1 million classified as short-term at December 31, 2010.

19. Supplemental Cash Flow Information

(In millions)	2011	2010	2009
Net cash provided from operating activities included:			
Interest paid (net of amounts capitalized)	$268	$107	$19
Income taxes paid to taxing authorities	2,893	2,155	1,663
Commercial paper and revolving credit arrangements, net:			
Commercial paper - issuances	$421	$-	$897
- repayments	(421)	-	(897)
Total	$-	$-	$-
Noncash investing and financing activities related to continuing operations:			
Additions to property, plant and equipment			
Asset retirement costs capitalized, excluding acquisitions	$151	$207	$135
Change in capital expenditure accrual	104	(140)	(28)
Debt payments made by United States Steel	214	105	144
Capital lease and sale-leaseback financing obligations increase	-	-	9

20. Defined Benefit Postretirement Plans

We have noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in Norway and the United Kingdom. Benefits under these plans are based on plan provisions specific to each plan.

We also have defined benefit plans for other postretirement benefits covering most employees. Health care benefits are provided through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Life insurance benefits are provided to certain retiree beneficiaries. Other postretirement benefits are not funded in advance.

Obligations and funded status - The accumulated benefit obligation for all defined benefit pension plans was $1,231 million and $2,737 million as of December 31, 2011 and 2010.

Summary information for our defined benefit pension plans follows. In 2011, both our U.S. and international plans have accumulated benefit obligations in excess of plan assets, while in 2010 only our U.S. plans had accumulated benefit obligations in excess of plan assets.

	December 31,		
	2011		2010
(In millions)	U.S.	Int'l	U.S.
Projected benefit obligation	$(986)	$(465)	$(3,221)
Accumulated benefit obligation	(813)	(418)	(2,365)
Fair value of plan assets	516	412	1,798

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

	Pension Benefits				Other Benefits	
	2011		2010		2011	2010
(In millions)	U.S.	Int' l	U.S.	Int' l		
Change in benefit obligations:						
Benefit obligations at January 1	$3,221	$ 415	$ 2,989	$ 395	$ 779	$ 685
Spin-off downstream business	(2,308)	-	-	-	(483)	-
Service cost	28	19	92	19	4	18
Interest cost	44	22	153	22	16	39
Plan amendment	-	11	-	-	-	-
Actuarial loss	84	13	287	6	1	69
Foreign currency exchange rate changes	-	(2)	-	(18)	-	-
Other	-	-	-	6	-	-
Benefits paid	(83)	(13)	(300)	(15)	(16)	(32)
Benefit obligations at December 31	$986	$465	$3,221	$415	$301	$779
Change in plan assets:						
Fair value of plan assets at January 1	$ 1,798	$389	$1,623	$348	$-	$-
Spin-off downstream business	(1,268)	-	-	-	-	-
Actual return on plan assets	30	15	214	47	-	-
Employer contributions	39	23	267	20	-	-
Foreign currency exchange rate changes	-	(2)	-	(14)	-	-
Other	-	-	(6)	3	-	-
Benefits paid	(83)	(13)	(300)	(15)	-	-
Fair value of plan assets at December 31	$516	$412	$1,798	$389	$-	$-
Funded status of plans at December 31	$(470)	$(53)	$(1,423)	$(26)	$(301)	$(779)
Amounts recognized in the consolidated balance sheet:						
Current liabilities	(17)	-	(21)	-	(18)	(36)
Noncurrent liabilities	(453)	(53)	(1,402)	(26)	(283)	(743)
Accrued benefit cost	$(470)	$(53)	$(1,423)	$(26)	$(301)	$(779)
Pretax amounts in accumulated other comprehensive income:						
Net loss	$432	$63	$1,382	$41	$16	$18
Prior service cost (credit)	27	11	81	-	(18)	(24)

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

Components of net periodic benefit cost and other comprehensive income – The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive income for our defined benefit pension and other postretirement plans.

	Pension Benefits								
	2011		2010		2009		Other Benefits		
(In millions)	U.S.	Int' l	U.S.	Int' l	U.S.	Int' l	2011	2010	2009
Components of net periodic benefit cost related to continuing operations:									
Service cost	$28	$19	$30	$19	$36	$14	$ 4	$ 3	$3
Interest cost	44	22	47	22	46	22	16	16	18
Expected return on plan assets	(43)	(23)	(44)	(22)	(47)	(21)	-	-	-
- prior service cost (credit)	6	-	6	-	6	1	(7)	(7)	(6)
- actuarial loss	47	2	48	5	20	2	-	-	-
Other	-	-	-	2	-	-	-	-	-
Net settlement/curtailment loss(a)	30	-	56	-	4	18	-	-	-
Net periodic benefit cost(b)	$112	$20	$143	$26	$65	$36	$ 13	$ 12	$15
Other changes in plan assets and benefit obligations recognized in other comprehensive income (pretax):									
Actuarial loss (gain)	$97	$24	$211	$(25)	$587	$52	$ 1	$ 69	$(34)
Amortization of actuarial (loss) gain	(77)	(2)	(167)	(5)	(33)	(7)	-	2	5
Prior service cost	-	(11)	-	-	-	-	-	-	-
Amortization of prior service credit (cost)	(6)	-	(13)	-	(13)	(1)	7	6	5
Spin off downstream business	(24)	-	-	-	-	-	-	-	-
Total recognized in other comprehensive income	$(10)	$11	$31	$(30)	$541	$44	$ 8	$ 77	$(24)
Total recognized in net periodic benefit cost and other comprehensive income	$102	$31	$174	$(4)	$606	$80	$ 21	$ 89	$(9)

(a) Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan' s total service and interest costs for the period. Such settlements occurred in one or more of our U.S. plans in 2011 and 2010. Additionally, in 2009 a curtailment and settlement was recorded related to our discontinued operations in Ireland as discussed in Note 6.

(b) Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

The estimated net loss and prior service cost for our defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2012 are $46 million and $7 million. The estimated prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2012 is $7 million.

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2011, 2010 and 2009.

	Pension Benefits								
	2011		2010		2009		Other Benefits		
(In millions)	U.S.	Int' l	U.S.	Int' l	U.S.	Int' l	2011	2010	2009
Weighted average assumptions used to determine benefit obligation:									
Discount rate	4.45%	4.70%	5.05%	5.40%	5.50%	5.70%	4.90%	5.55%	5.95%
Rate of compensation increase	5.00%	4.30%	5.00%	5.10%	4.50%	5.55%	5.00%	5.00%	4.50%

Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	5.05%	5.40%	5.23%	5.70%	6.90%	6.70%	5.55%	6.85%	6.85%
Expected long-term return on plan assets	8.50%[(a)]	5.86%	8.50%	6.40%	8.50%	6.10%	-	-	-
Rate of compensation increase	5.00%	5.10%	4.50%	5.55%	4.50%	4.75%	5.00%	4.50%	4.50%

(a) Due to the revised targeted asset allocation as discussed under the plan investment policies and strategies, effective January 1, 2012, the expected long term rate of return on plan assets was changed from 8.50 percent to 7.75 percent.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

Expected long-term return on plan assets

U.S. plan - The overall expected long-term return on plan assets assumption for our U.S. plan is determined based on an asset rate-of-return modeling tool developed by a third-party investment group. The tool utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plan' s asset allocation to derive an expected long-term rate of return on those assets. Capital market assumptions reflect the long-term capital market outlook. The assumptions for equity and fixed income investments are developed using a building-block approach, reflecting observable inflation information and interest rate information available in the fixed income markets. Long-term assumptions for other asset categories are based on historical results, current market characteristics and the professional judgment of our internal and external investment teams.

International plans - To determine the overall expected long-term return on plan assets assumption for our international plans, we consider the current level of expected returns on risk-free investments (primarily government bonds), the historical levels of the risk premiums associated with the other applicable asset categories and the expectations for future returns of each asset class. The expected return for each asset category is then weighted based on the actual asset allocation in our international pension plans to develop the overall expected long-term return on plan assets assumption.

Assumed health care cost trend rates

	2011	2010	2009
Health care cost trend rate assumed for the following year:			
Medical			
Pre-65	7.50 %	7.50 %	7.00%
Post-65	7.00 %	7.00 %	6.75%
Prescription drugs	7.50 %	7.50 %	7.50%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):			
Medical			
Pre-65	5.00 %	5.00 %	5.00%
Post-65	5.00 %	5.00 %	5.00%
Prescription drugs	5.00 %	5.00 %	5.00%
Year that the rate reaches the ultimate trend rate:			
Medical			
Pre-65	2018	2018	2014
Post-65	2017	2017	2015
Prescription drugs	2018	2018	2015

Assumed health care cost trend rates have a significant effect on the amounts reported for defined benefit retiree health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 2	$ 2
Effect on other postretirement benefit obligations	33	27

Plan investment policies and strategies

The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with the legal requirements of all applicable laws; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plans' investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation.

U.S. plan - Historical performance and future expectations suggest that common stocks will provide higher total investment returns than fixed income securities over a long-term investment horizon. Short-term investments are utilized for pension payments, expenses, and other liquidity needs. As such, for 2011 and prior, the plan's targeted asset allocation was comprised of 75 percent equity securities and 25 percent fixed income securities. Effective January 1, 2012, the U.S. plan's targeted asset allocation is comprised of 65 percent equity securities and 35 percent fixed income securities but may be adjusted accordingly to better match the plan's liabilities over time as the funded ratio (as defined by the investment policy) changes.

The plan's assets are managed by a third-party investment manager. The investment manager is limited to pursuing the investment strategies regarding asset mix and purchases and sales of securities within the parameters defined in the investment policy guidelines and investment management agreement. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

International plans - Our international plans' target asset allocation is comprised of 70 percent equity securities and 30 percent fixed income securities. The plan assets are invested in six separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers. Investments are diversified by industry and type, limited by grade and maturity. The use of derivatives by the investment managers is permitted, subject to strict guidelines. The investment managers' performance is measured independently by a third-party asset servicing consulting firm. Overall, investment performance and risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and periodic asset and liability studies.

Fair value measurements

Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2011 and 2010.

Cash and cash equivalents - Cash and cash equivalents include cash on deposit and an investment in a money market mutual fund that invests mainly in short-term instruments and cash, both of which are valued using a market approach and are considered Level 1 in the fair value hierarchy. The money market mutual fund is valued at the net asset value ("NAV") of shares held.

Equity securities - Investments in public investment trusts and S&P 500 exchange-traded funds are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. During the fourth quarter 2011, Level 1 investment trust holdings were liquidated and the proceeds were re-invested in an exchange traded fund. Non-public investment trusts are valued using a market approach based on the underlying investments in the trust, which are publicly-traded securities, and are considered Level 2. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership, determined using a combination of market, income and cost approaches, plus working capital, adjusted for liabilities, currency translation and estimated performance incentives. These private equity investments are considered Level 3.

Mutual funds - Investments in mutual funds are valued using a market approach. The shares or units held are traded on the public exchanges and such prices are Level 1 inputs.

Pooled funds - Investments in pooled funds are valued using a market approach at the NAV of units held, but investment opportunities in such funds are limited to institutional investors on the behalf of defined benefit plans. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. During the fourth quarter 2011, the U.S. plan's ownership interest held in the fixed income pooled fund was liquidated and the proceeds were re-invested in U.S. treasuries. Further, the U.S. plan's ownership interest held in the equity based pooled fund was liquidated and the proceeds were re-invested in an exchange traded fund. The majority of the pooled funds held by our international pension plans are benchmarked against a relative public index. These are considered Level 2.

U.S. treasuries - U.S. treasury notes are valued at the closing price reported in an active market. These notes are considered Level 1 investments.

Real estate - Real estate investments are valued based on discounted cash flows, comparable sales, outside appraisals, price per square foot or some combination thereof and therefore are considered Level 3.

Other - Other investments are composed of an investment in an unallocated annuity contract, an investment contract with an international insurance carrier, and investments in two limited liability companies ("LLCs") with no public market. The LLCs were formed to acquire timberland in the northwest and other properties. The investment in an unallocated annuity contract is valued using a market approach based on the experience of the assets held in an insurer's general account and is considered Level 2. The majority of the general account is invested in a well-diversified portfolio of high-quality fixed income securities, primarily consisting of investment-grade bonds. Investment income is allocated among pension plans participating in the general account based on the investment year method. Under this method, a record of the book value of assets held is maintained in subdivisions according to the calendar year in which the funds are invested. The earnings rate for each of these calendar year subdivisions varies from year to year, reflecting the actual earnings on the assets attributed to that year. The insurance carrier contract is funded by premiums paid annually by the participating plans and the funds are invested by the insurance carrier in portfolios with different risk profiles (low, medium, high) that can be elected by investors. The contract is valued using a market approach based on the underlying investments within the portfolio and is considered Level 2. The majority of the underlying investments consists of a well-diversified mix of non-U.S. publicly traded equity and fixed income securities. The values of the LLCs are determined using an income approach based on discounted cash flows and are considered Level 3.

The following table presents the fair values of our defined benefit pension plans' assets, by level within the fair value hierarchy, as of December 31, 2011 and 2010.

	December 31, 2011							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int' l	U.S.	Int' l	U.S.	Int' l	U.S.	Int' l
Cash and cash equivalents	$12	$2	$-	$-	$-	$-	$12	$2
Equity securities:								
Investment trusts	-	-	7	-	-	-	7	-
Exchange traded funds	324	-	-	-	-	-	324	-
Private equity	-	-	-	-	23	-	23	-
Investment funds								
Mutual funds - equity[a]	-	159	-	-	-	-	-	159
Pooled funds - equity[b]	-	-	-	96	-	-	-	96
Pooled funds - fixed income[c]	-	-	-	149	-	-	-	149
U.S. treasuries	92	-	-	-	-	-	92	-
Real estate[d]	-	-	-	-	21	-	21	-
Other	-	-	30 [e]	6	7	-	37	6
Total investments, at fair value	$428	$161	$37	$251	$ 51	$ -	$ 516	$412

	December 31, 2010							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int' l	U.S.	Int' l	U.S.	Int' l	U.S.	Int' l
Cash and cash equivalents	$8	$1	$-	$-	$-	$-	$8	$1
Equity securities:								
Investment trusts	25	-	137	-	-	-	162	-
Exchange traded funds	56	-	-	-	-	-	56	-
Private equity	-	-	-	-	67	-	67	-
Investment funds								
Mutual funds - equity[a]	-	161	-	-	-	-	-	161
Pooled funds - equity[b]	-	-	1,072	97	-	-	1,072	97
Pooled funds - fixed income[c]	-	-	350	126	-	-	350	126
Real estate[d]	-	-	-	-	54	-	54	-
Other	-	-	5	4	24	-	29	4
Total investments, at fair value	$ 89	$ 162	$ 1,564	$ 227	$ 145	$ -	$ 1,798	$ 389

(a) Includes approximately 70 percent of investments held in U.S. and non-U.S. common stocks in the financial services, consumer staples, health care, energy and basic material sectors and 30 percent of investments held among various other sectors. The funds objective is to outperform their respective benchmark indexes FTSE All Share, MSCI World Free, and MSCI Europe (excluding the U.K.) as defined by the investment policy.

(b) U.S. – At December 31, 2010, includes approximately 70 percent of investments held in U.S. and non-U.S. publicly traded common stocks in the consumer staples, consumer discretionary, technology, health and energy sectors and 30 percent of investments held among various other sectors. Int' l – Includes approximately 70 percent of investments held in non-U.S. common stocks (specifically Asia Pacific, except Japan, and the U.K.) in the financials, energy, consumer staples, industrials, and telecommunication services sectors and the 30 percent of investments held amongst various other sectors. The funds objective is to outperform their respective benchmark indexes, MSCI AC Asia and FTSE All-Share, as defined by the investment policy.

(c) U.S. – At December 31, 2010, includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include treasuries, mortgage-backed securities and industrials and 20 percent of investments held among various other sectors. Int' l – Includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include gilts, treasuries, financials, sovereigns and collateralized asset backed securities and 20 percent of investments held among various other sectors. The funds objective is to outperform their respective benchmark indexes, as defined by the investment policy.

(d) Includes investments diversified by property type and location. The largest property sector holdings, which represent approximately 70 percent of investments held, are office, hotel, residential and land with the greatest percentage of investments made in the U.S. and Asia, which includes the emerging markets of China and India.

(e) Includes an $18 million receivable for the sale of an investment that closed as of December 31, 2011 but did not cash settle until the next business day.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

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

	2011			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 67	$ 54	$ 24	$ 145
Spin-off downstream business	(46)	(37)	(17)	(100)
Actual return on plan assets	3	2	-	5
Purchases	3	4	-	7
Sales	(4)	(2)	-	(6)
Ending balance	$23	$21	$7	$51

	2010			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$42	$36	$23	$101
Actual return on plan assets	13	4	1	18
Purchases	15	17	-	32
Sales	(3)	(3)	-	(6)
Ending balance	$67	$54	$24	$145

Cash flows

Contributions to defined benefit plans - We expect to make contributions to the funded pension plans of up to $113 million in 2012. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $18 million and $21 million in 2012.

Estimated future benefit payments - The following gross benefit payments, which reflect expected future services, as appropriate, are expected to be paid in the years indicated.

	Pension Benefits		Other
(In millions)	U.S.	Int' l	Benefits[(a)]
2012	$ 104	$ 12	$ 21
2013	100	13	22
2014	102	15	22
2015	101	16	23
2016	104	18	24
2017 through 2021	482	105	121

(a) Expected Medicare reimbursements for 2012 through 2013 total $5 million. Effective 2013, as a result of the PPACA, future Medicare reimbursements will no longer be tax deductible and must be used to reduce the costs of providing Medicare Part D equivalent prescription drug benefits to retirees. The total of these future reimbursements from 2014 through 2021 is $22 million.

Contributions to defined contribution plans - We contribute to several defined contribution plans for eligible employees. Contributions to these plans related to continuing operations totaled $50 million in 2011, $75 million in 2010 and $59 million in 2009.

21. Incentive Based Compensation

Description of Stock Based Compensation Plans

The Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") was approved by our stockholders in April 2007 and authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights, stock awards (including restricted stock and restricted stock unit awards) and performance awards to employees. The 2007 Plan also allows us to provide equity compensation to our non-employee directors. No more than 34 million shares of our common stock may be issued under the 2007 Plan and no more than 12 million of those shares may be used for awards other than stock options or stock appreciation rights.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

Shares subject to awards under the 2007 Plan that are forfeited, are terminated or expire unexercised become available for future grants. If a stock appreciation right is settled upon exercise by delivery of shares of common stock, the full number of shares with respect to which the stock appreciation right was exercised will count against the number of shares of our common stock reserved for issuance under the 2007 Plan and will not again become available under the 2007 Plan. In addition, the number of shares of our common stock reserved for issuance under the 2007 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2007 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2007 Plan, no new grants were or will be made from the 2003 Incentive Compensation Plan (the "2003 Plan"). The 2003 Plan replaced the 1990 Stock Plan, the Non-Officer Restricted Stock Plan, the Non-Employee Director Stock Plan, the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors, the Senior Executive Officer Annual Incentive Compensation Plan and the Annual Incentive Compensation Plan (the "Prior Plans"). No new grants will be made from the Prior Plans. Any awards previously granted under the 2003 Plan or the Prior Plans shall continue to be exercisable in accordance with their original terms and conditions.

Stock based awards under the Plan

Stock options - We grant stock options under the 2007 Plan. Our stock options represent the right to purchase shares of our common stock at its fair market value on the date of grant. Through 2004, certain stock options were granted under the 2003 Plan with a tandem stock appreciation right, which allows the recipient to instead elect to receive cash or our common stock equal to the excess of the fair market value of shares of common stock, as determined in accordance with the 2003 Plan, over the option price of the shares. In general, stock options granted under the 2007 Plan and the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock appreciation rights - Prior to 2005, we granted SARs under the 2003 Plan. No stock appreciation rights have been granted under the 2007 Plan. Similar to stock options, stock appreciation rights represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. Under the 2003 Plan, certain SARs were granted as stock-settled SARs and others were granted in tandem with stock options. In general, SARs granted under the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Restricted stock - We grant restricted stock and restricted stock units under the 2007 Plan and previously granted such awards under the 2003 Plan. In 2005, the Compensation Committee began granting time-based restricted stock to certain of our U.S.-based officers as part of their annual long-term incentive package. The restricted stock awards to officers vest three years from the date of grant, contingent on the recipient' s continued employment. We also grant restricted stock to certain non-officer employees and restricted stock units to certain international employees ("restricted stock awards"), based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest in one-third increments over a three-year period, contingent on the recipient' s continued employment, however, certain restricted stock awards will vest over a four-year period, contingent on the recipient' s continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by our transfer agent.

Common stock units - We maintain an equity compensation program for our non-employee directors under the 2007 Plan and previously maintained such a program under the 2003 Plan. All non-employee directors receive annual grants of common stock units, and they are required to hold units granted prior to 2012 until they leave the Board of Directors. When dividends are paid on our common stock, directors receive dividend equivalents in the form of additional common stock units.

Total stock based compensation expense

Total employee stock based compensation expense related to continuing operations was $65 million, $51 million and $59 million in 2011, 2010 and 2009, while the total related income tax benefits were $23 million, $19 million and $22 million in the same years.

In 2011, 2010 and 2009 cash received upon exercise of stock option awards related was $77 million, $12 million and $4 million. Tax benefits realized for deductions for stock awards exercised during 2011, 2010 and 2009 totalled $32 million, $11 million and $10 million.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

Stock option awards

During 2011, 2010 and 2009, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following Black-Scholes assumptions:

	2011	2010	2009
Weighted average exercise price per share	$32.30	$30.00	$27.62
Expected annual dividend yield	2.1 %	3.2 %	3.5 %
Expected life in years	5.3	5.1	4.9
Expected volatility	40 %	43 %	41 %
Risk-free interest rate	1.7 %	2.2 %	2.3 %
Weighted average grant date fair value of stock option awards granted	$10.44	$8.70	$7.67

The following is a summary of stock option award activity in 2011.

	Number of Shares	Weighted Average Exercise price
Outstanding at beginning of year	24,912,261	$ 24.85
Granted	7,676,544	32.30
Exercised	(3,576,373)	15.12
Cancelled	(652,607)	25.88
Spin-off downstream business	(6,989,110)	30.94
Outstanding at end of year	21,370,715	$ 24.41

The intrinsic value of stock option awards exercised during 2011, 2010 and 2009 was $59 million, $8 million and $3 million.

The following table presents information related to stock option awards at December 31, 2011.

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Under Option	Weighted Average Exercise Price
$ 7.99-12.75	1,272,745	2	$ 10.23	1,272,745	$ 10.23
12.76-16.81	2,850,590	5	15.21	2,354,373	15.28
16.82-23.20	6,642,268	8	18.60	2,810,120	18.52
23.21-29.24	2,021,400	4	23.92	1,955,767	23.82
29.25-30.36	22,388	7	29.56	22,388	29.56
30.37-47.91	8,561,324	7	34.20	4,690,067	35.75
Total	21,370,715	6	24.41	13,105,460	24.11

As of December 31, 2011, the aggregate intrinsic value of stock option awards outstanding was $146 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable were $98 million and 5 years.

As of December 31, 2011, the number of fully-vested stock option awards and stock option awards expected to vest was 21,142,660. The weighted average exercise price and weighted average remaining contractual life of these stock option awards were $24.38 and 6 years and the aggregate intrinsic value was $145 million. As of December 31, 2011, unrecognized compensation cost related to stock option awards was $36 million, which is expected to be recognized over a weighted average period of 2 years.

Restricted stock awards

The following is a summary of restricted stock award activity

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	2,084,680	$ 23.03
Granted	3,066,978[(a)]	27.74
Vested	(993,949)	27.34
Forfeited	(163,806)	23.88
Spin-off downstream business	(289,925)	21.30
Unvested at end of year	3,703,978	25.88

(a) Beginning in August, 2011, most employees on the U.S., U.K., Canadian and Norwegian payrolls are eligible for a restricted stock grant, based on performance.

The vesting date fair value of restricted stock awards which vested during 2011, 2010 and 2009 was $30 million, $21 million and $24 million. The weighted average grant date fair value of restricted stock awards was $25.88, $23.03, and $44.89 for awards unvested at December 31, 2011, 2010 and 2009.

As of December 31, 2011, there was $78 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of 2.5 years.

Performance unit awards

Performance units provide for named executive officers to receive a cash payment upon the achievement of certain performance goals at the end of a defined measurement period. The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. The target value of each performance unit is $1, with the actual payout varying from $0 to $2 per unit (capped at a maximum payout of $2 per unit). Because performance units are to be settled in cash at the end of the performance period, they are accounted for as liability awards. Compensation expense related to continuing operations associated with performance units was $32 million and $2 million in 2011 and 2009, but was not significant in 2010. Expense for 2011 included $14 million paid on three groups of performance unit grants outstanding June 30, 2011, that were accelerated with the total payout determined based on performance through the effective date of the spin-off of our downstream business.

During the third quarter of 2011, we granted 15 million performance units to named executive officers. A portion of these units have an 18-month performance period and a portion have a 30-month performance period to reflect the remaining periods of the original 2011 and 2010 performance unit grants outstanding prior to the spinoff.

22. Stockholders' Equity

Securities exchangeable into Marathon common stock – In conjunction with our acquisition of Western Oil Sands Inc. ("Western") on October 18, 2007, Canadian residents were able to receive, at their election, cash, Marathon common stock or securities exchangeable into Marathon common stock (the "Exchangeable Shares"). The Exchangeable Shares were shares of an indirect Canadian subsidiary of Marathon and were exchanged into Marathon stock based upon an exchange ratio that began at one-for-one and adjusted quarterly to reflect cash dividends. The Exchangeable Shares were exchangeable at the option of the holder at any time and were automatically redeemable on October 18, 2011. They could also be redeemed prior to their automatic redemption if certain conditions were met. Those conditions were met and we filed notice of the proposed redemption in Canada on March 3, 2010. On April 7, 2010, the remaining exchangeable shares were redeemed.

Preferred shares - Also in connection with our acquisition of Western, the Board of Directors authorized a class of voting preferred stock. Upon completion of the acquisition, we issued shares of this voting preferred stock to a trustee, who held the shares for the benefit of the holders of the Exchangeable Shares discussed above. Each share of voting preferred stock was entitled to one vote on all matters submitted to the holders of Marathon common stock. Each holder of Exchangeable Shares could direct the trustee to vote the number of shares of voting preferred stock equal to the number of shares of Marathon common stock issuable upon the exchange of the Exchangeable Shares held by that holder. In no event would the aggregate number of votes entitled to be cast by the trustee with respect to the outstanding shares of voting preferred stock exceed the number of votes entitled to be cast with respect to the outstanding Exchangeable Shares. Except as otherwise provided in our restated certificate of incorporation or by applicable law, the common stock and the voting preferred stock voted together as a single class in the election of directors of Marathon and on all other matters submitted to a vote of stockholders of Marathon generally. The voting preferred stock had no other voting rights except as required by law. Other than dividends payable solely in shares of voting preferred stock, no dividend or other distribution, was paid or payable to the holder of the voting preferred stock. In the event of any liquidation, dissolution or winding up of Marathon, the holder of shares of the voting preferred stock would not be entitled to receive any assets of Marathon available for distribution to its stockholders. The voting preferred stock was not convertible into any other class or series of the capital stock of Marathon or into cash, property or other rights, and could not be redeemed. In connection with the redemption of the Exchangeable Shares, these preferred shares were eliminated in June 2010.

Share repurchase plan - The Board of Directors has authorized the repurchase of up to $5 billion of our common stock. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables. As of December 31, 2011, we had acquired 78 million common shares at a cost of $3,222 million under this authorized share repurchase program, including 12 million common shares acquired during 2011 at a cost of $300 million.

23. Leases

We lease a wide variety of facilities and equipment under operating leases, including land, building space, equipment and vehicles. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations (including sale-leasebacks accounted for as financings) and for operating lease obligations having initial or remaining noncancelable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2012	$ 22	$ 42
2013	1	38
2014	1	29
2015	1	26
2016	1	25
Later years	25	66
Sublease rentals	-	(2)
Total minimum lease payments	$51	$224
Less imputed interest costs	(20)	
Present value of net minimum lease payments	$31	

Operating lease rental expense related to continuing operations was $74 million, $77 million and $105 million in 2011, 2010 and 2009, which excludes $16 million and $3 million paid by United States Steel on assumed leases in 2010 and 2009.

24. Commitments and Contingencies

We are a 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 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.

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

Environmental matters – We are subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

At December 31, 2011 and 2010, accrued liabilities for remediation totaled $1 million and $119 million. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed.

Guarantees – We have provided certain guarantees, direct and indirect, of the indebtedness of other companies. Under the terms of most of these guarantee arrangements, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements. In addition to these financial guarantees, we also have various performance guarantees related to specific agreements.

United States Steel was the sole general partner of Clairton 1314B Partnership, L.P., which owned certain facilities formerly owned by United States Steel. We have agreed, under certain circumstances, to indemnify the limited partners if the partnership' s product sales fail to qualify for the credit under Section 29 of the Internal Revenue Code. The Clairton 1314B Partnership was terminated on October 31, 2008, but we were not released from our obligations. United States Steel has estimated the maximum potential amount of this indemnity obligation, including interest and tax gross-up, was approximately $110 million as of December 31, 2011, all of which is related to our continuing operations.

We have entered into other guarantees related to our continuing operations with maximum potential undiscounted payments totaling $139 million as of December 31, 2011, which consist primarily of leases of corporate assets containing general lease indemnities and guaranteed residual values, a performance guarantee and a long-term transportation services agreement.

In October 2010, upon acquiring a position in four exploration blocks in the Iraqi Kurdistan Region, we indemnified the KRG against any negative tax effects related to certain payments we are obligated to make to the KRG. As of December 31, 2011, some of those payments had been made, no related taxes have been assessed, and neither is there any history of such payments being taxed. Given the lack of history of tax assessment against such payments, and because certain of our future payments to the KRG are not quantifiable, a maximum potential undiscounted payments cannot be calculated.

Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

Contract commitments – At December 31, 2011 and 2010, contractual commitments of our continuing operations to acquire property, plant and equipment totaled $2,683 million and $1,881 million.

Other contingencies – During the second quarter of 2011, the AOSP operator determined the need and developed preliminary plans to address water flow into a previously mined and contained section of the Muskeg River mine. Our share of the estimated costs in the amount of $64 million was recorded to cost of revenues. At December 31, 2011, the remaining liability is $49 million.

Table of Contents

Selected Quarterly Financial Data (Unaudited)

(In millions, except per share data)	2011[a] 1st Qtr.	2011[a] 2nd Qtr.	2011[a] 3rd Qtr.	2011[a] 4th Qtr.	2010[a] 1st Qtr.	2010[a] 2nd Qtr.	2010[a] 3rd Qtr.	2010[a] 4th Qtr.
Revenues	$ 3,671	$ 3,694	$ 3,649	$ 3,649	$ 2,667	$ 2,807	$ 2,854	$ 3,362
Income from operations before income taxes	1,289	928	1,333	1,263	1,389	922	1,050	863
Income from continuing operations	455	298	405	549	617	374	467	424
Discontinued operations	541	698	-	-	(160)	335	229	282
Net income	$996	$996	$405	$549	$457	$709	$696	$706
Net income per share:								
Basic:								
Continuing operations	$0.64	$0.42	$0.57	$0.78	$0.87	$0.53	$0.66	$0.60
Discontinued operations	0.76	0.98	-	-	(0.23)	0.47	0.32	0.39
Net income	1.40	1.40	0.57	0.78	0.64	1.00	0.98	0.99
Diluted:								
Continuing operations	0.64	0.42	0.57	0.78	0.87	0.53	0.66	0.60
Discontinued operations	0.75	0.97	-	-	(0.23)	0.47	0.32	0.39
Net income	1.39	1.39	0.57	0.78	0.64	1.00	0.98	0.99
Dividends paid per share	$0.25	$0.25	$0.15	$0.15	$0.24	$0.25	$0.25	$0.25

(a) Our downstream business was spun-off on June 30, 2011. All quarters have been recast to reflect the business in discontinued operations.

[Table of Contents](#)

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the United States; Europe, which primarily includes activities in the United Kingdom, Norway and Poland; EG; Other Africa, which primarily includes activities in Angola and Libya; Canada; and Other International (“Other Int’ l”), which includes activities in Indonesia and the Iraqi Kurdistan Region. Discontinued operations (“Disc Ops”) represent our Irish and Gabonese oil exploration and production businesses that were sold in 2009.

Estimated Quantities of Proved Oil and Gas Reserves

The estimation of net recoverable quantities of liquid hydrocarbons, natural gas and synthetic crude oil is a highly technical process, which is based upon several underlying assumptions that are subject to change. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1 - Business.

(mmbbl)	United States	Canada[(a)]	EG [(b)]	Other Africa	Europe	Continuing Operations	Disc Ops
Liquid Hydrocarbons							
Proved developed and undeveloped reserves:							
Beginning of year - 2009	178	-	139	211	104	632	4
Revisions of previous estimates	-	-	(2)	3	19	20	2
Extensions, discoveries and other additions	21	-	-	31	12	64	-
Production	(23)	-	(15)	(17)	(33)	(88)	(2)
Sales of reserves in place	(6)	-	-	-	-	(6)	(4)
End of year - 2009	170	-	122	228	102	622	-
Revisions of previous estimates	(3)	-	10	-	23	30	-
Purchases of reserves in place	1	-	-	-	-	1	-
Extensions, discoveries and other additions	30	-	-	28	8	66	-
Production	(25)	-	(13)	(17)	(34)	(89)	-
End of year - 2010	173	-	119	239	99	630	-
Revisions of previous estimates	16	-	11	2	21	50	-
Improved recovery	1	-	-	-	-	1	-
Purchases of reserves in place	89	-	-	-	-	89	-
Extensions, discoveries and other additions	27	-	-	1	14	42	-
Production	(27)	-	(13)	(2)	(37)	(79)	-
End of year - 2011	279	-	117	240	97	733	-
Proved developed reserves:							
Beginning of year - 2009	137	-	99	193	81	510	4
End of year - 2009	120	-	83	186	87	476	-
End of year - 2010	124	-	86	180	89	479	-
End of year - 2011	141	-	78	179	84	482	-
Proved undeveloped reserves:							
Beginning of year - 2009	41	-	40	18	23	122	-
End of year - 2009	50	-	39	42	15	146	-
End of year - 2010	49	-	33	59	10	151	-
End of year - 2011	138	-	39	61	13	251	-

[Table of Contents](#)

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

	United States	Canada[a]	EG[b]	Other Africa	Europe	Continuing Operations	Disc Ops
Natural Gas *(bcf)*							
Proved developed and undeveloped reserves:							
Beginning of year - 2009	1,085	-	1,866	109	159	3,219	132
Revisions of previous estimates	(139)	-	(23)	-	(10)	(172)	-
Extensions, discoveries and other additions	80	-	-	-	2	82	-
Production[c]	(146)	-	(155)	(2)	(42)	(345)	(6)
Sales of reserves in place	(60)	-	-	-	-	(60)	(126)
End of year - 2009	820	-	1,688	107	109	2,724	-
Revisions of previous estimates	16	-	111	(1)	35	161	-
Purchases of reserves in place	1	-	-	-	-	1	-
Extensions, discoveries and other additions	61	-	-	-	4	65	-
Production[c]	(133)	-	(148)	(1)	(32)	(314)	-
Sales of reserves in place	(20)	-	-	-	-	(20)	-
End of year - 2010	745	-	1,651	105	116	2,617	-
Revisions of previous estimates	18	-	81	(1)	22	120	-
Purchases of reserves in place	119	-	-	-	-	119	-
Extensions, discoveries and other additions	109	-	-	-	11	120	-
Production[c]	(119)	-	(161)	-	(30)	(310)	-
End of year - 2011	872	-	1,571	104	119	2,666	-
Proved developed reserves:							
Beginning of year - 2009	839	-	1,273	109	95	2,316	34
End of year - 2009	652	-	1,102	107	50	1,911	-
End of year - 2010	591	-	1,186	104	43	1,924	-
End of year - 2011	551	-	1,104	104	40	1,799	-
Proved undeveloped reserves:							
Beginning of year - 2009	246	-	593	-	64	903	98
End of year - 2009	168	-	586	-	59	813	-
End of year - 2010	154	-	465	1	73	693	-
End of year - 2011	321	-	467	-	79	867	-
Synthetic crude oil *(mmbbl)*							
Proved developed and undeveloped reserves:							
Beginning of year - 2009	-	-	-	-	-	-	-
Revisions of previous estimates[d]	-	603	-	-	-	603	-
End of year - 2009	-	603	-	-	-	603	-
Revisions of previous estimates	-	(22)	-	-	-	(22)	-
Production	-	(9)	-	-	-	(9)	-
End of year - 2010	-	572	-	-	-	572	-
Revisions of previous estimates	-	17	-	-	-	17	-
Production	-	(14)	-	-	-	(14)	-
Extensions, discoveries and other additions	-	48	-	-	-	48	-
End of year - 2011	-	623	-	-	-	623	-

Proved developed reserves:							
Beginning of year - 2009	-	-	-	-	-	-	-
End of year - 2009	-	392	-	-	-	392	-
End of year - 2010	-	433	-	-	-	433	-
End of year - 2011	-	623	-	-	-	623	-
Proved undeveloped reserves:							
Beginning of year - 2009	-	-	-	-	-	-	-
End of year - 2009	-	211	-	-	-	211	-
End of year - 2010	-	139	-	-	-	139	-
End of year - 2011	-	-	-	-	-	-	-

Table of Contents

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmboe)	United States	Canada[(a)]	EG[(b)]	Other Africa	Europe	Continuing Operations	Disc Ops
Total Proved Reserves							
Proved developed and undeveloped reserves:							
Beginning of year - 2009	359	-	450	229	131	1,169	26
Revisions of previous estimates[(d)]	(22)	603	(6)	3	17	595	1
Extensions, discoveries and other additions	34	-	-	31	13	78	-
Production[(c)]	(48)	-	(41)	(17)	(41)	(147)	(2)
Sales of reserves in place	(16)	-	-	-	-	(16)	(25)
End of year - 2009	307	603	403	246	120	1,679	-
Revisions of previous estimates	(1)	(22)	29	-	28	34	-
Purchases of reserves in place	1	-	-	-	-	1	-
Extensions, discoveries and other additions	40	-	-	28	9	77	-
Production[(c)]	(47)	(9)	(38)	(17)	(39)	(150)	-
Sales of reserves in place	(3)	-	-	-	-	(3)	-
End of year - 2010	297	572	394	257	118	1,638	-
Revisions of previous estimates	19	17	25	1	25	87	-
Improved recovery	1	-	-	-	-	1	-
Purchases of reserves in place	109	-	-	-	-	109	-
Extensions, discoveries and other additions	45	48	-	1	16	110	-
Production[(c)]	(47)	(14)	(40)	(2)	(42)	(145)	-
End of year - 2011	424	623	379	257	117	1,800	-
Proved developed reserves:							
Beginning of year - 2009	277	-	312	211	96	896	10
End of year - 2009	229	392	267	204	95	1,187	-
End of year - 2010	222	433	284	198	96	1,233	-
End of year - 2011	233	623	262	196	91	1,405	-
Proved undeveloped reserves:							
Beginning of year - 2009	82	-	138	18	35	273	16
End of year - 2009	78	211	136	42	25	492	-
End of year - 2010	75	139	110	59	22	405	-
End of year - 2011	191	-	117	61	26	395	-

(a) Synthetic crude oil proved reserves were added as of December 31, 2009.

(b) Consists of estimated reserves from properties governed by production sharing contracts.

(c) Excludes the resale of purchased natural gas utilized in reservoir management.

(d) Volumes for Canada are after 10 million barrels of synthetic crude oil production in 2009.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

	December 31,						
(In millions)	United States	Canada	EG	Other Africa	Europe	Other Int' l	Total
2011 Capitalized costs:							
Proved properties	$15,288	$9,209	$1,545	$1,678	$8,342	$33	$36,095
Unproved properties	4,344	1,473	23	303	51	179	6,373
Total	19,632	10,682	1,568	1,981	8,393	212	42,468
Accumulated depreciation, depletion and amortization:							
Proved properties	8,499	572	729	134	6,593	1	16,528
Unproved properties	359	-	-	9	-	12	380
Total	8,858	572	729	143	6,593	13	16,908
Net capitalized costs	$10,774	$10,110	$839	$1,838	$1,800	$199	$25,560
2010 Capitalized costs:							
Proved properties	$12,008	$8,362	$1,518	$1,437	$8,032	$24	$31,381
Unproved properties	1,450	1,626	24	277	46	122	3,545
Total	13,458	9,988	1,542	1,714	8,078	146	34,926
Accumulated depreciation, depletion and amortization:							
Proved properties	7,049	381	625	122	5,927	1	14,105
Unproved properties	325	-	-	9	-	8	342
Total	7,374	381	625	131	5,927	9	14,447
Net capitalized costs	$6,084	$9,607	$917	$1,583	$2,151	$137	$20,479

Costs Incurred for Property Acquisition, Exploration and Development[(a)]

(In millions)		United States	Canada	EG	Other Africa	Europe	Other Int' l	Continuing Operations	Disc Ops	Total
2011	Property acquisition:									
	Proved	$1,782	$5	$1	$-	$-	$-	$ 1,788	$-	$1,788
	Unproved	3,271	-	-	1	7	57	3,336	-	3,336
	Exploration	782	42	-	33	109	168	1,134	-	1,134
	Development	889	293	18	294	388	-	1,882	-	1,882
	Total	$6,724	$340	$19	$328	$504	$ 225	$ 8,140	$-	$8,140
2010	Property acquisition:									
	Proved	$1	$-	$-	$-	$-	$-	$ 1	$-	$1
	Unproved	400	-	-	1	2	103	506	-	506
	Exploration	520	10	1	41	43	153	768	-	768
	Development	855	889	13	315	465	-	2,537	-	2,537
	Total	$1,776	$ 899	$14	$357	$510	$256	$ 3,812	$-	$3,812
2009	Property acquisition:									
	Proved	$-	$11	$-	$-	$-	$-	$ 11	$ 15	$26
	Unproved	127	1	-	6	-	2	136	-	136
	Exploration	271	11	-	127	81	29	519	-	519
	Development	1,150	976	23	266	354	-	2,769	64	2,833

Total	$ 1,548	$999	$ 23	$ 399	$ 435	$31	$ 3,435	$79	$ 3,514

(a) Includes costs incurred whether capitalized or expensed.

Table of Contents

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

(In millions)		United States	Canada	EG	Other Africa	Europe	Other Int' l	Total
2011	Revenues and other income:							
	Sales	$ 3,063	$ 1,388	$29	$ 216	$1,010	$-	$5,706
	Transfers	63	-	905	-	3,560	-	4,528
	Other income[a]	41	-	-	-	15	-	56
	Total revenues and other income	3,167	1,388	934	216	4,585	-	10,290
	Expenses:							
	Production costs	(954)	(814)[b]	(117)	(33)	(350)	-	(2,268)
	Exploration expenses	(378)	(10)	(1)	(10)	(81)	(164)	(644)
	Depreciation, depletion and amortization[c]	(1,471)	(196)	(104)	(11)	(685)	-	(2,467)
	Administrative expenses	(67)	(10)	(2)	(1)	(19)	(15)	(114)
	Total expenses	(2,870)	(1,030)	(224)	(55)	(1,135)	(179)	(5,493)
	Results before income taxes	297	358	710	161	3,450	(179)	4,797
	Income tax (provision) benefit	(104)	(90)	(254)	(168)	(2,203)	63	(2,756)
	Results of continuing operations	$193	$268	$456	$(7)	$1,247	$(116)	$2,041
2010	Revenues and other income:							
	Sales	$2,429	$692	$11	$1,473	$697	$-	$5,302
	Transfers	93	-	701	-	2,319	-	3,113
	Other income[a]	17	-	-	812	(64)	-	765
	Total revenues and other income	2,539	692	712	2,285	2,952	-	9,180
	Expenses:							
	Production costs	(815)	(596)	(108)	(70)	(297)	-	(1,886)
	Exploration expenses	(275)	(5)	(21)	(47)	(32)	(118)	(498)
	Depreciation, depletion and amortization[c]	(1,463)	(109)	(110)	(36)	(687)	-	(2,405)
	Administrative expenses	(52)	(9)	(1)	2	(20)	(10)	(90)
	Total expenses	(2,605)	(719)	(240)	(151)	(1,036)	(128)	(4,879)
	Results before income taxes	(66)	(27)	472	2,134	1,916	(128)	4,301
	Income tax (provision) benefit	26	7	(187)	(1,647)	(658)	46	(2,413)
	Results of continuing operations	$(40)	$(20)	$285	$487	$1,258	$(82)	$1,888
2009	Revenues and other income:							
	Sales[d]	$1,839	$599	$23	$1,146	$699	$-	$4,306
	Transfers	24	-	587	-	1,678	-	2,289
	Other income[a]	185	-	-	-	13	-	198
	Total revenues and other income	2,048	599	610	1,146	2,390	-	6,793
	Expenses:							
	Production costs	(763)	(371)	(108)	(62)	(289)	-	(1,593)
	Exploration expenses	(153)	(16)	-	(73)	(37)	(28)	(307)
	Depreciation, depletion and amortization[c]	(846)	(126)	(115)	(37)	(736)	-	(1,860)
	Administrative expenses	(53)	(9)	(1)	(3)	(13)	(22)	(101)
	Total expenses	(1,815)	(522)	(224)	(175)	(1,075)	(50)	(3,861)
	Results before income taxes	233	77	386	971	1,315	(50)	2,932

Income tax (provision) benefit	(76)	(17)	(112)	(770)	(678)	14	(1,639)
Results of continuing operations	$157	$60	$274	$201	$637	$(36)	$ 1,293
Results of discontinued operations	$-	$-	$-	$194	$79	$-	$273

(a) Includes net gain on disposal of assets.

(b) 2011 Canada production costs include $64 million for the OSM water abatement.

(c) Includes long-lived asset impairments.

(d) Excludes noncash effects of changes in the fair value of certain natural gas sales contracts in the United Kingdom which expired September 2009.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

The following reconciles results of continuing operations for oil and gas producing activities to segment income:

(In millions)	2011	2010	2009
Results of continuing operations	$2,041	$1,888	$1,293
Items not included in results of continuing oil and gas operations, net of tax:			
Marketing income and technology costs	(53)	(11)	(24)
Income from equity method investments	213	167	110
Other third-party income[a]	10	(5)	9
Other	(1)	(2)	(4)
Items not allocated to segment income, net of tax:			
Gain on asset disposition	(23)	(449)	(122)
Long-lived asset impairments	178	303	-
Water abatement-OSM	48	-	-
Segment income not included in results of continuing oil and gas operations:			
Integrated Gas	178	142	90
Segment income	$2,591	$2,033	$1,352

[a] Includes revenues, net of associated costs and income taxes, from activities that support our production operations, which may include processing or transportation of third-party production and the purchase and subsequent resale of natural gas utilized for reservoir management.

Standardized Measure of Discounted Future Net Cash Flows

	December 31,					
(In millions)	United States	Canada	EG	Other Africa	Europe	Total
2011						
Future cash inflows	$28,108	$59,365	$7,318	$30,007	$12,120	$136,918
Future production and administrative costs	(10,751)	(28,048)	(1,931)	(1,269)	(2,752)	(44,751)
Future development costs	(6,341)	(10,346)	(435)	(874)	(1,702)	(19,698)
Future income tax expenses	(2,740)	(4,490)	(1,368)	(25,821)	(5,147)	(39,566)
Future net cash flows	$8,276	$16,481	$3,584	$2,043	$2,519	$32,903
10 percent annual discount for estimated timing of cash flows	(4,539)	(11,845)	(1,330)	(733)	(528)	(18,975)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$3,737	$4,636	$2,254	$1,310	$1,991	$13,928
2010						
Future cash inflows	$15,349	$41,901	$5,366	$20,815	$8,800	$92,231
Future production and administrative costs	(6,878)	(21,675)	(1,469)	(996)	(2,275)	(33,293)
Future development costs	(2,084)	(9,688)	(441)	(907)	(1,535)	(14,655)
Future income tax expenses	(1,726)	(1,821)	(1,208)	(17,201)	(2,956)	(24,912)
Future net cash flows	$4,661	$8,717	$2,248	$1,711	$2,034	$19,371
10 percent annual discount for estimated timing of cash flows	(2,008)	(6,168)	(795)	(825)	(295)	(10,091)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$2,653	$2,549	$1,453	$886	$1,739	$9,280
2009						
Future cash inflows	$12,094	$32,207	$4,620	$14,974	$6,901	$70,796

Future production and administrative costs	(6,796)	(21,044)	(1,514)	(876)	(2,373)	(32,603)
Future development costs	(1,362)	(6,715)	(462)	(677)	(1,752)	(10,968)
Future income tax expenses	(923)	(60)	(935)	(12,419)	(1,253)	(15,590)
Future net cash flows	$3,013	$4,388	$1,709	$1,002	$1,523	$11,635
10 percent annual discount for estimated timing of cash flows	(1,041)	(3,658)	(625)	(571)	(85)	(5,980)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$1,972	$730	$1,084	$431	$1,438	$5,655

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Changes in the Standardized Measure of Discounted Future Net Cash Flows

(In millions)	2011	2010	2009
Sales and transfers of oil and gas produced, net of production and administrative costs	$(7,922)	$(6,330)	$(4,876)
Net changes in prices and production and administrative costs related to future production	12,313	9,843	4,840
Extensions, discoveries and improved recovery, less related costs	1,454	1,268	1,399
Development costs incurred during the period	1,899	2,546	2,786
Changes in estimated future development costs	(1,349)	(2,153)	(3,773)
Revisions of previous quantity estimates	2,526	1,117	5,110
Net changes in purchases and sales of minerals in place	233	(20)	(159)
Accretion of discount	2,040	1,335	787
Net change in income taxes	(6,676)	(4,231)	(4,345)
Timing and other	130	250	(149)
Net change for the year	4,648	3,625	1,620
Beginning of the year	9,280	5,655	4,035
End of year	$13,928	$9,280	$5,655

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(In millions)	2011	2010	2009
Segment Income (Loss)			
Exploration and Production			
United States	$366	$251	$52
International	1,791	1,690	1,166
E&P segment	2,157	1,941	1,218
Oil Sands Mining	256	(50)	44
Integrated Gas	178	142	90
Segment income	2,591	2,033	1,352
Items not allocated to segments, net of income taxes	(884)	(151)	(636)
Income from continuing operations	1,707	1,882	716
Discontinued operations[(a)]	1,239	686	747
Net income	$2,946	$2,568	$1,463
Capital Expenditures[(b)]			
Exploration and Production			
United States	$2,145	$1,528	$1,420
International	893	946	742
E&P segment	3,038	2,474	2,162
Oil Sands Mining	308	874	1,115
Integrated Gas	2	2	2
Corporate	51	46	42
Total	$3,399	$3,396	$3,321
Exploration Expenses			
United States	$379	$275	$153
International	265	223	154
Total	$644	$498	$307

(a) The spin-off of our downstream business was completed on June 30, 2011 and all periods have been recast to reflect the downstream business as discontinued operations. In addition, our businesses in Ireland and Gabon were sold in 2009 and are reflected as discontinued operations in 2009.

(b) Capital expenditures include changes in accruals.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	2011	2010	2009
E&P Operating Statistics			
Net Liquid Hydrocarbon Sales *(mbbld)*			
United States	75	70	64
Europe	101	92	92
Africa	43	83	87
Total International	144	175	179
Worldwide continuing operations	219	245	243
Discontinued operations	-	-	5
Worldwide	219	245	248
Natural gas liquids included in above	17	16	19
Natural Gas Sales *(mmcfd)*[c]			
United States	326	364	373
Europe	97	105	138
Africa	443	409	430
Total International	540	514	568
Worldwide continuing operations	866	878	941
Discontinued operations	-	-	17
Worldwide	866	878	958
Total Worldwide Sales *(mboed)*			
Continuing operations	363	391	400
Discontinued operations	-	-	7
Worldwide	363	391	407
Average Realizations[d]			
Liquid Hydrocarbons (per bbl)			
United States	$92.55	$72.30	$54.67
Europe	115.55	81.95	64.46
Africa	73.21	71.71	53.91
Total International	102.96	77.11	59.31
Worldwide continuing operations	99.37	75.73	58.09
Discontinued operations	-	-	56.47
Worldwide	$99.37	$75.73	$58.06
Natural Gas (per mcf)			
United States	$4.95	$4.71	$4.14
Europe	9.84	7.10	4.90
Africa[e]	0.24	0.25	0.25
Total International	1.97	1.65	1.38
Worldwide continuing operations	3.09	2.91	2.47
Discontinued operations	-	-	8.54
Worldwide	$3.09	$2.91	$2.58

(c) Includes natural gas acquired for injection and subsequent resale of 16 mmcfd, 18 mmcfd and 22 mmcfd for the years 2011, 2010 and 2009.

(d) Excludes gains and losses on derivative instruments.

(e) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and EGHoldings, equity method investees. We include our share of Alba Plant LLC' s income in our E&P segment and we include our share of AMPCO' s and EGHoldings' income in our Integrated Gas segment.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

(In millions, except as noted)	2011	2010	2009
OSM Operating Statistics			
Net Synthetic Crude Oil Sales *(mbbld)*[(f)]	43	29	32
Synthetic Crude Average Oil Realizations (per bbl)[(d)]	$91.65	$71.06	$56.44
IG Operating Statistics			
Net Sales (mtd)			
LNG[(g)]	7,086	6,859	6,642
Methanol	1,282	1,049	1,192
Proved Reserves			
Net Proved Reserves at year-end (developed and undeveloped)			
Liquid Hydrocarbons *(mmbbl)*			
United States	279	173	170
International	454	457	452
Worldwide	733	630	622
Natural Gas *(bcf)*			
United States	872	745	820
International	1,794	1,872	1,904
Worldwide	2,666	2,617	2,724
Synthetic Crude Oil *(mmbbl)*			
Canada	623	572	603
Total Proved Reserves *(mmboe)*	1,800	1,638	1,679

(f) Includes blendstocks.

(g) Includes both consolidated sales volumes and our share of the sales volumes of equity method investees. LNG sales from Alaska, conducted through a consolidated subsidiary, ceased when these operations were sold in the third quarter of 2011. LNG and methanol sales from Equatorial Guinea are conducted through equity method investees.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this Report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

See Item 8. Financial Statements and Supplementary Data – Management' s Report on Internal Control over Financial Reporting and – Report of Independent Registered Public Accounting Firm. During the fourth quarter of 2011, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information concerning our directors required by this item is incorporated by reference to the material appearing under the heading "Election of Directors" in our Proxy Statement for the 2012 Annual Meeting of Stockholders.

Our Board of Directors has established the Audit and Finance Committee and determined our "Audit Committee Financial Expert." The related information required by this item is incorporated by reference to the material appearing under the sub-heading "Audit and Finance Committee" located under the heading "The Board of Directors and Governance Matters" in our Proxy Statement for the 2012 Annual Meeting of Stockholders.

We have adopted a Code of Ethics for Senior Financial Officers. It is available on our website at http://marathonoil.com/Code_Ethics_Sr_Finan_Off

Executive Officers of the Registrant

See Item 1. Business – Executive Officers of the Registrant for the names, ages and titles of our executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires that our directors and executive officers, and persons who own more than ten percent of a registered class of our equity securities, file reports of beneficial ownership on Form 3 and changes in beneficial ownership on Form 4 or Form 5 with the Securities and Exchange Commission. Based solely on our review of the reporting forms and written representations provided to us from the individuals required to file reports, we believe that each of our directors and executive officers has complied with the applicable reporting requirements for transactions in Marathon Oil securities during the fiscal year ended December 31, 2011.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to the material appearing under the heading "Executive Compensation Tables and Other Information;" under the sub-headings "Compensation Committee" and "Compensation Committee Interlocks and

Insider Participation" under the heading "The Board of Directors and Governance Matters;" and under the heading "Compensation Committee Report" in our Proxy Statement for the 2012 Annual Meeting of stockholders.

Table of Contents

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information concerning security ownership of certain beneficial owners and management required by this item is incorporated by reference to the material appearing under the headings "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Directors and Executive Officers" in our Proxy Statement for the 2012 Annual Meeting of stockholders.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2011 with respect to shares of Marathon Oil common stock that may be issued under our existing equity compensation plans:

2007 Incentive Compensation Plan (the "2007 Plan")

2003 Incentive Compensation Plan (the "2003 Plan") – No additional awards will be granted under this plan.

1990 Stock Plan – No additional awards will be granted under this plan.

Deferred Compensation Plan for Non-Employee Directors – No additional awards will be granted under this plan.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights[c]	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by stockholders	20,776,749 [a]	$ 24.41	11,994,866 [d]
Equity compensation plans not approved by stockholders	20,984 [b]	N/A	–
Total	20,797,733	N/A	11,994,866

[a] Includes the following:

16,802,543 stock options outstanding under the 2007 Plan;

2,835,382 stock options outstanding under the 2003 Plan and the net number of stock-settled SARs that could be issued from this Plan. The number of stock-settled SARs is based on the closing price of Marathon Oil common stock on December 31, 2011 of $29.27 per share;

54,578 stock options and SARs outstanding under the 1990 Stock Plan;

238,083 common stock units that have been credited to non-employee directors pursuant to the non-employee director deferred compensation program and the annual director stock award program established under the 2007 Plan and the 2003 Plan; common stock units credited under the 2007 Plan and the 2003 Plan were 186,822 and 51,261;

846,163 restricted stock units granted to non-officers under the 2007 Plan and outstanding as of December 31, 2011.

In addition to the awards reported above 2,863,487 shares of restricted stock were issued and outstanding as of December 31, 2011, but subject to forfeiture restrictions under the 2007 Plan.

[b] Reflects awards of common stock units made to non-employee directors under the Deferred Compensation Plan for Non-Employee Directors prior to April 30, 2003. When a non-employee director leaves the Board, he or she will be issued actual shares of Marathon Oil common stock in place of the common stock units.

[c] Weighted-average exercise prices do not take the restricted stock units or common stock units into account as these awards have no exercise price.

[d] Reflects the shares available for issuance under the 2007 Plan. No more than 7,765,713 of these shares may be issued for awards other than stock options or stock appreciation rights. In addition, shares related to grants that are forfeited, terminated, cancelled or expire unexercised shall again immediately become available for issuance.

The Deferred Compensation Plan for Non-Employee Directors is our only equity compensation plan that has not been approved by our stockholders. Our authority to make equity grants under this plan was terminated effective April 30, 2003. Under the Deferred

Compensation Plan for Non-Employee Directors, all non-employee directors were required to defer half of their annual retainers in the form of common stock units. On the date the retainer would have otherwise been payable to the non-employee director, we credited an unfunded bookkeeping account for each non-employee director with a number of common stock units equal to half of his or her annual retainer divided by the fair market value of our common stock on that date. The ongoing value of each common stock unit equals the market price of a share of our common stock. When the non-employee director leaves the Board, he or she is issued actual shares of our common stock equal to the number of common stock units in his or her account at that time.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to the material appearing under the heading "Certain Relationships and Related Person Transactions," and under the sub-heading "Board and Committee Independence" under the heading "The Board of Directors and Governance Matters" in our Proxy Statement for the 2012 Annual Meeting of stockholders.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated by reference to the material appearing under the heading "Information Regarding the Independent Registered Public Accounting Firm' s Fees, Services and Independence" in our Proxy Statement for the 2012 Annual Meeting of stockholders.

[Table of Contents](#)

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements (see Part II, Item 8. of this report regarding financial statements)

2. Financial Statement Schedules

   Financial statement schedules required under SEC rules but not included in this Report are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

3. Exhibits:

Any reference made to USX Corporation in the exhibit listing that follows is a reference to the former name of Marathon Oil Corporation, a Delaware corporation and the registrant, and is made because the exhibit being listed and incorporated by reference was originally filed before July 2001, the date of the change in the registrant' s name. References to Marathon Ashland Petroleum LLC or MAP are references to the entity now known as Marathon Petroleum Corporation.

Exhibit Number	Exhibit Description	Incorporated by Reference: Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
2	**Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession**						
2.1++	Separation and Distribution dated May 25, 2011 among Marathon Oil Corporation, Marathon Oil Company and Marathon Petroleum Corporation	8-K	2.1	5/26/2011			
2.2++	Purchase and Sale Agreement between Hilcorp Resources Holding, LP and Marathon Oil Company dated May 31, 2011	10-Q/A	2.2	10/18/ 2011			
3	**Articles of Incorporation and Bylaws**						
3.1	Restated Certificate of Incorporation of Marathon Oil Corporation	8-K	3.1	4/25/2007			
3.2	By-Laws of Marathon Oil Corporation	10-Q/A	3.1	5/13/2011			
3.3	Specimen of Common Stock Certificate	8-K	3.3	5/14/2007			
4	**Instruments Defining the Rights of Security Holders, Including Indentures**						
4.1	Five Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, ABN Ambro Bank N.V., Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-K	4.1	2/26/2010			
4.2	Amendment No. 1 dated as of May 4, 2006 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-Q	4.1	5/8/2006			

4.3	Amendment No. 2 dated as of May 7, 2007 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-Q	4.1	8/7/2007

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
4.4	Amendment No. 3 dated as of October 4, 2007 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-Q	4.1	11/7/2007			
4.5	Amendment No. 4 dated as of April 3, 2008 to Five-Year Credit Agreement dated as of May 20, 2004 among Marathon Oil Corporation, the Co-Agents and other Lenders party thereto, Bank of America, N.A., as Syndication Agent, Citibank, N.A. and Morgan Stanley Bank, as Documentation Agent	10-Q	4.2	5/9/2008			
4.6	Indenture dated February 26, 2002 between Marathon and The Bank of New York Trust Company, N.A., successor in interest to JPMorgan Chase Bank as Trustee, relating to senior debt securities of Marathon	S-3	4.4	7/26/2007	333-144874		
	Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10% of the total consolidated assets of Marathon. Marathon hereby agrees to furnish a copy of any such instrument to the Commission upon its request						
10	**Material Contracts**						
10.1	Tax Sharing Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Petroleum Corporation and MPC Investment LLC	8-K	10.1	5/26/2011			
10.2	Transition Services Agreement dated as of May 25, 2011 among Marathon Oil Corporation and Marathon Petroleum Corporation	8-K	10.3	5/26/2011			
10.3	Employee Matters Agreement dated as of May 25, 2011 among Marathon Oil Corporation and Marathon Petroleum Corporation	8-K	10.2	5/26/2011			

10.4	Amendment to Employee Matters Agreement dated as of June 30, 2011 among Marathon Oil Corporation and Marathon Petroleum Corporation	10-Q	10.3	8/8/2011	
10.5	Marathon Oil Corporation 2007 Incentive Compensation Plan				X
10.6	Form of Non-Qualified Stock Option Award Agreement for Officers granted under Marathon Oil Corporation' s 2007 Incentive Compensation Plan, effective May 30, 2007				X

Table of Contents

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.7	Form of Non-Qualified Stock Option Award Agreement for Officers granted under Marathon Oil Corporation' s 2007 Incentive Compensation Plan, effective February 24, 2010	10-K	10.5	2/28/2011			
10.8	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation' s 2007 Incentive Compensation Plan, effective May 30, 2007					X	
10.9	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation' s 2007 Incentive Compensation Plan, effective February 24, 2010	10-K	10.7	2/28/2011			
10.10	Form of Performance Unit Award Agreement (18 month Performance Cycle) for Section 16 Officers granted under Marathon Oil Corporation' s 2007 Incentive Compensation Plan, effective July 27, 2011					X	
10.11	Form of Performance Unit Award Agreement (18 month Performance Cycle) for Officers granted under Marathon Oil Corporation' s 2007 Incentive Compensation Plan, effective July 27, 2011					X	
10.12	Form of Performance Unit Award Agreement (30 month Performance Cycle) for Section 16 Officers granted under Marathon Oil Corporation' s 2007 Incentive Compensation Plan, effective July 27, 2011					X	
10.13	Form of Performance Unit Award Agreement (30 month Performance Cycle) for Officers granted under Marathon Oil Corporation' s 2007 Incentive Compensation Plan, effective July 27, 2011					X	
10.14	Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts	10-K	10.10	2/28/2011			

10.15	Marathon Oil Corporation 2003 Incentive Compensation Plan, Effective January 1, 2003	10-K	10.9	2/26/2010
10.16	Marathon Oil Corporation 1990 Stock Plan (as Amended and Restated) Effective January 1, 2002	10-Q	10.1	11/7/2008
10.17	First Amendment to Marathon Oil Corporation 1990 Stock Plan (as Amended and Restated) Effective January 1, 2002	10-Q	10.2	11/7/2008
10.18	Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors	10-K	10.14	2/27/2009

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	Exhibit	Filing Date	SEC File No.		
10.19	Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation' s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.14	2/26/2010			
10.20	Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation' s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.15	2/26/2010			
10.21	Form of Non-Qualified Stock Option with Tandem Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation' s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.16	2/26/2010			
10.22	Form of Stock Appreciation Right Award Agreement for Chief Executive Officer granted under Marathon Oil Corporation' s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.18	2/26/2010			
10.23	Form of Stock Appreciation Right Award Agreement for Executive Committee members granted under Marathon Oil Corporation' s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.19	2/26/2010			
10.24	Form of Stock Appreciation Right Award Agreement for Officers granted under Marathon Oil Corporation' s 2003 Incentive Compensation Plan, effective January 1, 2003	10-K	10.2	2/26/2010			
10.25	Form of Non-Qualified Stock Option Award Agreement granted under Marathon Oil Corporation' s 2003 Incentive Compensation Plan	10-K	10.21	2/26/2010			
10.26	Form of Officer Restricted Stock Award Agreement granted under Marathon Oil Corporation' s 2003 Incentive Compensation Plan	10-K	10.22	2/26/2010			

10.27	Form of Performance Unit Award Agreement (2005-2007 Performance Cycle) granted under Marathon Oil Corporation' s 2003 Incentive Compensation Plan	10-K	10.23	2/26/2010
10.28	Form of Non-Qualified Stock Option Award Agreement granted under Marathon Oil Corporation' s 2007 Incentive Compensation Plan	10-K	10.24	2/26/2010

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
10.29	Form of Performance Unit Award Agreement (2010-2012 Performance Cycle) granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan	10-K	10.25	2/26/2010			
10.30	Form of Non-Qualified Stock Option Award Agreement granted under Marathon Oil Corporation's 2007 Incentive Compensation Plan	10-K	10.26	2/26/2010			
10.31	Marathon Oil Company Excess Benefit Plan Amended and Restated					X	
10.32	Marathon Oil Company Deferred Compensation Plan Amended and Restated Effective June 30, 2011					X	
10.33	Executive Tax, Estate, and Financial Planning Program	10-K	10.32	2/27/2009			
10.34	Executive Change in Control Severance Benefits Plan	10-K	10.35	2/27/2009			
12.1	Computation of Ratio of Earnings to Fixed Charges					X	
14.1	Code of Ethics for Senior Financial Officers	10-K	14.1	2/26/2010			
21.1	List of Significant Subsidiaries					X	
23.1	Consent of Independent Registered Public Accounting Firm					X	
23.2	Consent of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists					X	
23.3	Consent of Ryder Scott Company, L.P., independent petroleum engineers and geologists					X	
23.4	Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists					X	
31.1	Certification of Chairman, President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934					X	
31.2	Certification of Executive Vice President and Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934					X	

32.1	Certification of Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350					X
32.2	Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350					X
99.1	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2011					X
99.2	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2010	10-K	99.1	2/28/2011		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.	Filed Herewith	Furnished Herewith
99.3	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2009	10-K	99.1	2/26/2010			
99.4	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2011					X	
99.5	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2011					X	
99.6	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2009	10-K/A	99.3	9/17/2010			
101.INS	XBRL Instance Document					X	
101.SCH	XBRL Taxonomy Extension Schema					X	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase					X	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase					X	
101.LAB	XBRL Taxonomy Extension Label Linkbase					X	
101.DEF	XBRL Taxonomy Extension Definition Linkbase					X	

++ **Marathon Oil agrees to furnish supplementally a copy of any omitted schedule to the United States Securities and Exchange Commission upon request.**

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 29, 2012

MARATHON OIL CORPORATION

By: /s/ MICHAEL K. STEWART
Michael K. Stewart
Vice President, Finance and Accounting, Controller and Treasurer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on February 29, 2012 on behalf of the registrant and in the capacities indicated.

Signature	Title
/S/ CLARENCE P. CAZALOT, JR. Clarence P. Cazalot, Jr.	Chairman, President and Chief Executive Officer
/S/ JANET F. CLARK Janet F. Clark	Executive Vice President and Chief Financial Officer
/S/ MICHAEL K. STEWART Michael K. Stewart	Vice President, Finance and Accounting, Controller and Treasurer
/S/ GREGORY H. BOYCE Gregory H. Boyce	Director
/S/ PIERRE BRONDEAU Pierre Brondeau	Director
/S/ LINDA Z. COOK Linda Z. Cook	Director
/S/ SHIRLEY ANN JACKSON Shirley Ann Jackson	Director
/S/ PHILIP LADER Philip Lader	Director
/S/ MICHAEL E. J. PHELPS Michael E. J. Phelps	Director
/S/ DENNIS H. REILLEY Dennis H. Reilley	Director

Exhibit 10.5

MARATHON OIL CORPORATION
2007 INCENTIVE COMPENSATION PLAN

1. *Plan.* The Marathon Oil Corporation 2007 Incentive Compensation Plan (the "Plan") was adopted by the Board of Directors of Marathon Oil Corporation, a Delaware corporation (the "Corporation"), to reward certain officers and employees of the Corporation and its Subsidiaries and Non-employee Directors of the Corporation by providing for certain cash benefits and by enabling them to acquire shares of Common Stock of the Corporation.

2. *Objectives.* The Plan is designed to attract and retain officers and employees of the Corporation and its Subsidiaries, to attract and retain qualified directors of the Corporation, to encourage the sense of proprietorship of such officers, employees and directors and to stimulate the active interest of such persons in the development and financial success of the Corporation and its Subsidiaries. These objectives are to be accomplished by making Awards under this Plan and thereby providing Participants with a proprietary interest in the growth and performance of the Corporation and its Subsidiaries.

3. *Definitions.* As used herein, the terms set forth below shall have the following respective meanings:

"Administrator" means (i) with respect to Employee Awards, the Committee, and (ii) with respect to Director Awards, the Board.

"Authorized Officer" means the Chief Executive Officer of the Corporation (or any other senior officer of the Corporation to whom he or she shall delegate the authority to execute any Award Agreement, where applicable).

"Award" means an Employee Award or a Director Award.

"Award Agreement" means any Employee Award Agreement or Director Award Agreement.

"Board" means the Board of Directors of the Corporation.

"Cash Award" means an award denominated in cash.

"Code" means the Internal Revenue Code of 1986, as amended from time to time.

"Committee" means the independent Committee of the Board as is designated by the Board to administer the Plan.

"Common Stock" means Marathon Oil Corporation common stock, par value $1.00 per share.

"Corporation" has the meaning set forth in paragraph 1 hereof.

"Director Award" means any Nonqualified Stock Option, SAR, Stock Award, Restricted Stock Unit Award, Cash Award or Performance Award granted, whether singly, in combination or in tandem, to a Participant who is a Non-employee Director pursuant to such applicable terms, conditions and limitations (including treatment as a Performance Award) as the Board may establish in order to fulfill the objectives of the Plan.

"Director Award Agreement" means a written agreement setting forth the terms, conditions and limitations applicable to a Director Award, to the extent the Board determines such agreement is necessary.

"Disability" means a condition that renders the Participant disabled under the terms of the Long Term Disability Plan of Marathon Oil Company, the Speedway SuperAmerica LLC Long Term Disability Plan, or a successor thereto, as applicable.

"Dividend Equivalents" means, with respect to Restricted Stock Units, an amount equal to all dividends and other distributions (or the economic equivalent thereof) that are payable to stockholders of record during the Restriction Period on a like number of shares of Common Stock granted in the Award.

"Employee" means an employee of the Corporation or any of its Subsidiaries.

"Employee Award" means any Option, SAR, Stock Award, Restricted Stock Unit Award, Cash Award or Performance Award granted, whether singly, in combination or in tandem, to a Participant who is an Employee pursuant to such applicable terms, conditions and limitations (including treatment as a Performance Award) as the Committee may establish in order to fulfill the objectives of the Plan.

"Employee Award Agreement" means a written agreement setting forth the terms, conditions and limitations applicable to an Employee Award, to the extent the Committee determines such agreement is necessary.

"Equity Award" means any Option, SAR, Stock Award, or Performance Award (other than a Performance Award denominated in cash) granted to a Participant under the Plan.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Fair Market Value" of a share of Common Stock means, as of a particular date, (i) if Common Stock is listed on a national securities exchange, the closing sales price per share of such Common Stock on the consolidated transaction reporting system for the principal national securities exchange on which shares of Common Stock are listed on that date, or, if there shall have been no such sale so reported on that date, on the next succeeding date on which such a sale is so reported, or, at the discretion of the Committee, the price prevailing on the exchange at the time of exercise, (ii) if Common Stock is not so listed but is quoted on the NASDAQ Stock Market, Inc., the closing sales price per share of Common Stock reported by the NASDAQ Stock Market, Inc. on that date, or, if there shall have been no such sale so reported on that date, on the next succeeding date on which such a sale is so reported or, at the discretion of the Committee, the price prevailing on the NASDAQ Stock Market, Inc. at the time of exercise, (iii) if Common Stock is not so listed or quoted, the closing bid price on that date, or, if there are no quotations available for such date, on the next succeeding date on which such quotations shall be available, as reported by the NASDAQ Stock Market, Inc. or, if not reported by the NASDAQ

Stock Market, Inc., by the National Quotation Bureau Incorporated or (iv) if Common Stock is not publicly traded, the most recent value determined by an independent appraiser appointed by the Corporation for such purpose.

"Grant Date" means the date an Award is granted to a Participant pursuant to the Plan.

"Grant Price" means the price at which a Participant may exercise his or her right to receive cash or Common Stock, as applicable, under the terms of an Award.

"Incentive Stock Option" means an Option that is intended to comply with the requirements set forth in Section 422 of the Code.

"Non-employee Director" means an individual serving as a member of the Board who is not an Employee of the Corporation or any of its Subsidiaries.

"Nonqualified Stock Option" means an Option that is not an Incentive Stock Option.

"Option" means a right to purchase a specified number of shares of Common Stock at a specified Grant Price, which may be an Incentive Stock Option or a Nonqualified Stock Option.

"Participant" means an Employee or Non-employee Director to whom an Award has been granted under this Plan.

"Performance Award" means an Award made pursuant to this Plan that is subject to the attainment of one or more performance goals.

"Performance Goal" means a standard established by the Committee to determine in whole or in part whether a Qualified Performance Award shall be earned.

"Plan" has the meaning set forth in paragraph 1 hereof.

"Qualified Performance Award" means a Performance Award made to a Participant who is an Employee that is intended to qualify as qualified performance-based compensation under Section 162(m) of the Code, as described in Section 8(v)(B) of the Plan.

"Restricted Stock" means Common Stock that is restricted or subject to forfeiture provisions.

"Restricted Stock Unit" means a unit evidencing the right to receive in specified circumstances one share of Common Stock or equivalent value in cash that is restricted or subject to forfeiture provisions.

"Restricted Stock Unit Award" means an Award in the form of Restricted Stock Units.

"Restriction Period" means a period of time beginning as of the Grant Date of an Award of Restricted Stock or Restricted Stock Units and ending as of the date upon which the Common Stock subject to such Award is issued (if not previously issued) or is no longer restricted or subject to forfeiture provisions.

"Retirement" means termination on or after the time at which the Employee is eligible for retirement under the Retirement Plan of Marathon Oil Company, the Marathon Petroleum Company LLC Retirement Plan, or a successor thereto, as applicable. However, the term Retirement does not include (i) an event immediately following which the Participant remains an Employee, or (ii) a termination that does not coincide with the Employee' s retirement under the Retirement Plan of Marathon Oil Company, the Marathon Petroleum Company LLC Retirement Plan, or a successor thereto, as applicable.

"Stock Appreciation Right" or "SAR" means a right to receive a payment, in cash or Common Stock, equal to the excess of the Fair Market Value or other specified valuation of a specified number of shares of Common Stock on the date the right is exercised over a specified Grant Price.

"Stock Award" means an Award in the form of, or denominated in, or by reference to, shares of Common Stock, including an award of Restricted Stock.

"Subsidiary" means (i) in the case of a corporation, any corporation of which the Corporation directly or indirectly owns shares representing 50% or more of the combined voting power of the shares of all classes or series of capital stock of such corporation which have the right to vote generally on matters submitted to a vote of the stockholders of such corporation and (ii) in the case of a partnership or other business entity not organized as a corporation, any such business entity of which the Corporation directly or indirectly owns 50% or more of the voting, capital or profits interests (whether in the form of partnership interests, membership interests or otherwise).

4. *Eligibility.*

(a) *Employees.* Employees eligible for the grant of Employee Awards under this Plan are those selected by the Committee.

(b) *Directors*. Members of the Board eligible for the grant of Director Awards under this Plan are those who are Non-employee Directors.

5. *Common Stock Available for Awards.* Subject to the provisions of paragraph 16 hereof, no Award shall be granted if it shall result in the aggregate number of shares of Common Stock issued under the Plan plus the number of shares of Common Stock covered by or subject to Awards then outstanding (after giving effect to the grant of the Award in question) to exceed 17,000,000 shares. No more than 6,000,000 shares of Common Stock shall be available for Awards other than Options or SARs. The number of shares of Common Stock that are the subject of Awards under this Plan that are forfeited, terminated or expire unexercised shall again immediately become available for Awards hereunder. Notwithstanding the foregoing, in the case of any SAR settled upon exercise by delivery of shares of Common Stock, the full number of shares with respect to which the SAR was exercised shall count against the number of shares of

Common Stock reserved for issuance and shall not again become available under this Plan. The number of shares of Common Stock reserved for issuance under the Plan shall not be increased by (i) any shares tendered or Award surrendered in connection with the purchase of shares of Common Stock upon the exercise of an Option as described in paragraph 12, (ii) any shares of Common Stock deducted from an Award payment in connection with the Corporation' s tax withholding obligations as described in paragraph 13 or (iii) any shares of Common Stock purchased by the Corporation with proceeds collected in connection with the exercise of an Option. The Committee may from time to time adopt and observe such procedures concerning the counting of shares against the Plan maximum as it may deem appropriate. The Board and the appropriate officers of the Corporation shall from time to time take whatever actions are necessary to file any required documents with governmental authorities, stock exchanges and transaction reporting systems to ensure that shares of Common Stock are available for issuance pursuant to Awards.

6. *Administration.*

(a) Authority of the Committee. This Plan shall be administered by the Committee except as otherwise provided herein. Subject to the provisions hereof, the Committee shall have full and exclusive power and authority to administer this Plan and to take all actions that are specifically contemplated hereby or are necessary or appropriate in connection with the administration hereof. The Committee shall also have full and exclusive power to interpret this Plan and to adopt such rules, regulations and guidelines for carrying out this Plan as it may deem necessary or proper, all of which powers shall be exercised in the best interests of the Corporation and in keeping with the objectives of this Plan. Subject to paragraph 6(d) hereof, the Committee may, in its discretion, provide for the extension of the exercisability of an Employee Award, accelerate the vesting or exercisability of an Employee Award or otherwise amend or modify an Employee Award in any manner that is (i) not adverse to the Participant to whom such Employee Award was granted, (ii) consented to by such Participant or (iii) authorized by paragraph 16(c) hereof; *provided, however*, that no such action shall permit the term of any Option to be greater than 10 years from the applicable Grant Date. The Committee may correct any defect or supply any omission or reconcile any inconsistency in this Plan or in any Award in the manner and to the extent the Committee deems necessary or desirable to further the Plan purposes. Any decision of the Committee, with respect to Employee Awards, in the interpretation and administration of this Plan shall lie within its sole and absolute discretion and shall be final, conclusive and binding on all parties concerned.

(b) Indemnification. No member of the Committee or officer of the Corporation to whom the Committee has delegated authority in accordance with the provisions of paragraph 7 of this Plan shall be liable for anything done or omitted to be done by him or her, by any member of the Committee or by any officer of the Corporation in connection with the performance of any duties under this Plan, except for his or her own willful misconduct or as expressly provided by statute.

(c) Authority of the Board. The Board shall have the same powers, duties, and authority to administer the Plan with respect to Director Awards as the Committee retains with respect to Employee Awards as described above.

(d) Prohibition on Repricing of Awards. No Option or SAR may be repriced, replaced, regranted through cancellation or modified without stockholder approval (except in connection with a change in the Corporation' s capitalization or a transaction as contemplated in paragraph 16 hereof), if the effect would be to reduce the Grant Price for the shares underlying such Award.

7. *Delegation of Authority.* The Committee may delegate to the Chief Executive Officer and to other senior officers of the Corporation its authority under this Plan pursuant to such conditions or limitations as the Committee may establish with respect to Employee Awards. The Board may delegate to the Chief Executive Officer and to other senior officers of the Corporation its administrative functions under this Plan with respect to Director Awards. The Committee and Board, as applicable, may engage or authorize the engagement of a third party administrator to carry out administrative functions under the Plan.

8. *Employee Awards.*

(a) The Committee shall determine the type or types of Employee Awards to be made under this Plan and shall designate from time to time the Employees who are to be the recipients of such Awards. Each Employee Award shall be evidenced in such communications as the Committee deems appropriate, including in an Employee Award Agreement, shall contain such terms, conditions and limitations as shall be determined by the Committee in its sole discretion, and may be signed by an Authorized Officer for and on behalf of the Corporation. Employee Awards may consist of those listed in this paragraph 8(a) and may be granted singly, in combination or in tandem. Employee Awards may also be granted in combination or in tandem with, in replacement of, or as alternatives to, grants or rights under this Plan or any other employee plan of the Corporation or any of its Subsidiaries, including the plan of any acquired entity. All or part of an Award may be subject to conditions established by the Committee. Upon the termination of employment by a Participant who is an Employee, any unexercised, deferred, unvested or unpaid Awards shall be treated as provided in the terms and conditions of the applicable Award.

(i) *Option.* An Employee Award may be in the form of an Option. An Option awarded to an Employee pursuant to this Plan may consist of either an Incentive Stock Option or a Nonqualified Stock Option. On the Grant Date, the Grant Price of an Option shall be not less than the Fair Market Value of the Common Stock subject to such Option. The term of the Option shall extend no more than 10 years after the Grant Date. Options may not include provisions that "reload" the option upon exercise. Subject to the foregoing provisions, the terms, conditions and limitations applicable to any Options awarded to Employees pursuant to this Plan, including the Grant Price, the term of the Options, the number of shares subject to the Option and the date or dates upon which they become exercisable, shall be determined by the Committee.

(ii) *Stock Appreciation Rights.* An Employee Award may be in the form of an SAR. On the Grant Date, the Grant Price of an SAR shall be not less than the Fair Market Value of the Common Stock subject to such SAR. The holder of a tandem SAR may elect to exercise either the option or the SAR, but not both. The exercise period for an SAR shall extend no more than 10 years after the Grant Date. SARs may not include provisions that "reload" the SAR upon exercise. Subject to the foregoing provisions, the terms, conditions and limitations applicable to any SARs awarded to Employees pursuant to this Plan, including the Grant Price, the term of any SARs and the date or dates upon which they become exercisable, shall be determined by the Committee.

(iii) *Stock Award.* An Employee Award may be in the form of a Stock Award. The terms, conditions and limitations applicable to any Stock Award, including, but not limited to, vesting or other restrictions, shall be determined by the Committee. Any Stock Award settled in Common Stock that (a) is not a Performance Award shall have a minimum Restriction Period of three years from the date of grant or (b) is a Performance Award shall have a minimum Restriction Period of one year from the date of grant; *provided, however*, that (1) the Committee may provide for earlier vesting upon a change in control or upon an Employee' s termination of employment by reason of death, Disability or Retirement, (2) such three-year or one-year minimum Restriction Period, as applicable, shall not apply to a Stock Award that is granted in lieu of salary or bonus, and (3) vesting of a Stock Award may occur incrementally over the three-year or one-year minimum Restriction Period, as applicable.

(iv) *Restricted Stock Unit Awards*. An Employee Award may be in the form of a Restricted Stock Unit Award. The terms, conditions and limitations applicable to a Restricted Stock Unit Award, including, but not limited to, the Restriction Period and the right to Dividend Equivalents, shall be determined by the Committee. Any Restricted Stock Unit Award settled in Common Stock that (a) is not a Performance Award shall have a minimum Restriction Period of three years from the date of grant or (b) is a Performance Award shall have a minimum Restriction Period of one year from the date of grant; *provided, however*, that (1) the Committee may provide for earlier vesting upon a change in control or upon an Employee' s termination of employment by reason of death, Disability or Retirement, (2) such three-year or one-year minimum Restriction Period, as applicable, shall not apply to a Restricted Stock Unit Award that is granted in lieu of salary or bonus, and (3) vesting of a Restricted Stock Unit Award may occur incrementally over the three-year or one-year minimum Restriction Period, as applicable.

(v) *Cash Award.* An Employee Award may be in the form of a Cash Award. The terms, conditions and limitations applicable to any Cash Awards granted to Employees pursuant to this Plan, including, but not limited to, vesting or other restrictions, shall be determined by the Committee.

(vi) *Performance Award.* Without limiting the type or number of Employee Awards that may be made under the other provisions of this Plan, an Employee Award may be in the form of a Performance Award. The terms, conditions and limitations applicable to an Employee Award that is a Performance Award shall be determined by the Committee. The Committee shall set performance goals in its discretion which, depending on the extent to which they are met, will determine the value and/or amount of Performance Awards that will be paid out to the Employee and/or the portion that may be exercised.

(A) *Nonqualified Performance Awards*. Performance Awards granted to Employees that are not intended to qualify as qualified performance-based compensation under Section 162(m) of the Code shall be based on achievement of such goals and be subject to such terms, conditions and restrictions as the Committee or its delegate shall determine.

(B) *Qualified Performance Awards.* Performance Awards granted to Employees under the Plan that are intended to qualify as qualified performance-based compensation under Section 162(m) of the Code shall be paid, vested or otherwise deliverable solely on account of the attainment of one or more pre-established, objective Performance Goals established by the Committee prior to the earlier to occur of (x) 90 days after the commencement of the period of service to which the Performance Goal relates or (y) the lapse of 25% of the period of service (as scheduled in good faith at the time the goal is established), and in any event while the outcome is substantially uncertain. A Performance Goal is objective if a third party having knowledge of the relevant facts could determine whether the goal is met. Such a Performance Goal may be based on one or more business criteria that apply to the Employee, one or more business segments, units, or divisions of the Corporation, or the Corporation as a whole, and if so desired by the Committee, by comparison with a peer group of companies. A Performance Goal may include one or more of the following:

Stock price measures (including but not limited to growth measures and total stockholder return);

Earnings per share (actual or targeted growth);

Earnings before interest, taxes, depreciation, and amortization (“EBITDA”);

Economic value added (“EVA”);

Net income measures (including but not limited to income after capital costs and income before or after taxes);

Operating income;

Cash flow measures;

Return measures (including but not limited to return on capital employed);

Operating measures (including but not limited to refinery throughput, oil and gas reserves, and production);

Expense targets (including but not limited to finding and development costs and general and administrative expenses);

Margins;

Reserve replacement ratio, reserve additions, or other reserve level measures;

Refined product measures; and

Corporate values measures (including but not limited to diversity commitment, ethics compliance, environmental, and safety).

Unless otherwise stated, such a Performance Goal need not be based upon an increase or positive result under a particular business criterion and could include, for example, maintaining the status quo or limiting economic losses (measured, in each case, by reference to specific business criteria). In interpreting Plan provisions applicable to Performance Goals and Qualified Performance Awards, it is the intent of the Plan to conform with the standards of Section 162(m) of the Code and Treasury Regulation §1.162-27(e)(2)(i), as to grants to those Employees whose compensation is, or is likely to be, subject to Section 162(m) of the Code, and the Committee in establishing such goals and interpreting the Plan shall be guided by such provisions. Prior to the payment of any compensation based on the achievement of Performance Goals, the Committee must certify in writing that applicable Performance Goals and any of the material terms thereof were, in fact, satisfied. Subject to the foregoing provisions, the terms, conditions and limitations applicable to any Qualified Performance Awards made pursuant to this Plan shall be determined by the Committee.

(b) Notwithstanding anything to the contrary contained in this Plan, the following limitations shall apply to any Employee Awards made hereunder:

(i) no Employee may be granted, during any calendar year, Employee Awards consisting of Options or SARs that are exercisable for more than 3,000,000 shares of Common Stock;

(ii) no Employee may be granted, during any calendar year, Employee Awards consisting of Stock Awards or Restricted Stock Units covering or relating to more than 1,000,000 shares of Common Stock (the limitation set forth in this clause (ii) and the limitation set forth in clause (i) above being hereinafter collectively referred to as "Stock Based Awards Limitations"); and

(iii) no Employee may be granted Qualified Performance Awards consisting of cash in respect of any calendar year having a maximum payment value determined on the Grant Date in excess of $20,000,000.

9. *Director Awards.* The Board may grant Director Awards to the Non-employee Directors of the Corporation from time to time in accordance with this paragraph 9. Director Awards may consist of those listed in this paragraph 9 and may be granted singly, in combination or in tandem. Each Director Award may, in the discretion of the Board, be embodied in a Director Award Agreement, which shall contain such terms, conditions and limitations as shall be determined by the Board in its sole discretion.

(a) *Option.* A Director Award may be in the form of an Option. An Option awarded to a Non-employee Director pursuant to this Plan may consist of a Nonqualified Stock Option. On the Grant Date, the Grant Price of an Option shall be not less than the Fair Market Value of the Common Stock subject to such Option. The term of the Option shall extend no more than 10 years after the Grant Date. Options may not include provisions that "reload" the option upon exercise. Subject to the foregoing provisions, the terms, conditions and limitations applicable to any Options awarded to Non-employee Directors pursuant to this Plan, including the Grant Price, the term of the Options, the number of shares subject to the Option and the date or dates upon which they become exercisable, shall be determined by the Board.

(b) *Stock Appreciation Rights.* A Director Award may be in the form of an SAR. On the Grant Date, the Grant Price of an SAR shall be not less than the Fair Market Value of the Common Stock subject to such SAR. The holder of a tandem SAR may elect to exercise either the option or the SAR, but not both. The exercise period for an SAR shall extend no more than 10 years after the Grant Date. SARs may not include provisions that "reload" the SAR upon exercise. Subject to the foregoing provisions, the terms, conditions and limitations applicable to any SARs awarded to Non-employee Directors pursuant to this Plan, including the Grant Price, the term of any SARs and the date or dates upon which they become exercisable, shall be determined by the Board.

(c) *Stock Awards*. A Director Award may be in the form of a Stock Award. Terms, conditions and limitations applicable to any Stock Awards granted to a Non-employee Director pursuant to this Plan shall be determined by the Board.

(d) *Restricted Stock Unit Awards*. A Director Award may be in the form of a Restricted Stock Unit Award. The terms, conditions and limitations applicable to a Restricted Stock Unit Award, including, but not limited to, the Restriction Period and the right to Dividend Equivalents, shall be determined by the Board.

(e) *Performance Awards*. Without limiting the type or number of Director Awards that may be made under the other provisions of this Plan, a Director Award may be in the form of a Performance Award. Terms, conditions and limitations applicable to any Performance Awards granted to a Non-employee Director pursuant to this Plan shall be determined by the Board. The Board shall set performance goals in its discretion which, depending on the extent to which they are met, will determine the value and/or amount of Performance Awards that will be paid out to the Non-employee Director.

10. *Non-United States Participants.* The Committee may grant awards to persons outside the United States under such terms and conditions as may, in the judgment of the Committee, be necessary or advisable to comply with the laws of the applicable foreign jurisdictions and, to that end, may establish sub-plans, modified option exercise procedures and other terms and procedures. Notwithstanding the above, the Committee may not take any actions hereunder, and no Awards shall be granted, that would violate the Exchange Act, the Code, any securities law, any governing statute, or any other applicable law.

11. *Payment of Awards.*

(a) *General.* Payment of Awards may be made in the form of cash or Common Stock, or a combination thereof, and may include such restrictions as the Administrator shall determine, including, but not limited to, in the case of Common Stock, restrictions on transfer and forfeiture provisions. For an Award of Restricted Stock, the certificates evidencing the shares of such Restricted Stock (to the extent that such shares are so evidenced) shall contain appropriate legends and restrictions that describe the terms and conditions of the restrictions applicable thereto. For an Award of Restricted Stock Units, the shares of Common Stock that may be issued at the end of the Restriction Period shall be evidenced by book entry registration or in such other manner as the Administrator may determine.

(b) *Deferral.* With the approval of the Administrator, amounts payable in respect of Awards may be deferred and paid either in the form of installments or as a lump-sum payment; *provided, however*, that if deferral is permitted, each provision of the Award shall be interpreted to permit the deferral only as allowed in compliance with the requirements of Section 409A of the Code, and any provision that would conflict with such requirements shall not be valid or enforceable. The Administrator may permit selected Participants to elect to defer payments of some or all types of Awards in accordance with procedures established by the Administrator. Any deferred payment pursuant to an Award, whether elected by the Participant or specified by the Award Agreement or the terms of the Award or by the Administrator, may be forfeited if and to the extent that the Award Agreement or the terms of the Award so provide.

(c) *Dividends and Interest.* Rights to (i) dividends will be extended to and made part of any Stock Award and (ii) Dividend Equivalents may be extended to and made part of any Restricted Stock Unit, subject in each case to such terms, conditions and restrictions as the Administrator may establish. The Administrator may also establish rules and procedures for the crediting of interest on deferred cash payments for Awards.

12. *Option Exercise.* The Grant Price shall be paid in full at the time of exercise in cash or, if elected by the Participant, the Participant may purchase such shares by means of tendering Common Stock or surrendering another Award, including Restricted Stock, valued at Fair Market Value on the date of exercise, or any combination thereof. The Committee shall determine acceptable methods for Participants to tender Common Stock or other Awards; provided that any Common Stock that is or was the subject of an Award may be so tendered only if it has been held by the Participant for at least six months. The Committee may provide for procedures to permit the exercise or purchase of such Awards by use of the proceeds to be received from the sale of Common Stock issuable pursuant to an Award (including "cashless exercise"). Unless otherwise provided in the applicable Award Agreement, in the event shares of Restricted Stock are tendered as consideration for the exercise of an Option, a number of the shares issued upon the exercise of the Option, equal to the number of shares of Restricted Stock used as consideration thereof, shall be subject to the same restrictions as the Restricted Stock so

submitted as well as any additional restrictions that may be imposed by the Committee. The Committee may adopt additional rules and procedures regarding the exercise of Options from time to time, provided that such rules and procedures are not inconsistent with the provisions of this paragraph.

13. *Taxes.* The Corporation or its designated third party administrator shall have the right to deduct applicable taxes from any Employee Award payment and withhold, at the time of delivery or vesting of cash or shares of Common Stock under this Plan, an appropriate amount of cash or number of shares of Common Stock or a combination thereof for payment of taxes or other amounts required by law or to take such other action as may be necessary in the opinion of the Corporation to satisfy all obligations for withholding of such taxes. The Committee may also permit withholding to be satisfied by the transfer to the Corporation of shares of Common Stock theretofore owned by the holder of the Employee Award with respect to which withholding is required. If shares of Common Stock are used to satisfy tax withholding, such shares shall be valued based on the Fair Market Value when the tax withholding is required to be made.

14. *Amendment, Modification, Suspension or Termination of the Plan.* The Committee may amend, modify, suspend or terminate this Plan for the purpose of meeting or addressing any changes in legal requirements or for any other purpose permitted by law, except that (i) any amendment, modification, suspension, or termination of paragraph 9 of this Plan shall be approved by the Board, (ii) no amendment or alteration that would adversely affect the rights of any Participant under any Award previously granted to such Participant shall be made without the consent of such Participant and (iii) no amendment or alteration shall be effective prior to its approval by the stockholders of the Corporation to the extent such approval is required by applicable legal requirements or the requirements of the securities exchange on which the Corporation' s stock is listed.

15. *Assignability.* Unless otherwise determined by the Administrator and expressly provided in the Award Agreement, no Award or any other benefit under this Plan shall be assignable or otherwise transferable except by will or the laws of descent and distribution. The Administrator may, in its sole discretion, permit a Participant to designate a beneficiary with respect to an Award, and in the event that a beneficiary designation conflicts with an assignment by will, the beneficiary designation will prevail. The Administrator may prescribe and include in applicable Award Agreements or the terms of the Award other restrictions on transfer. In no event may an Option or SAR be transferred for consideration. Any attempted assignment of an Award or any other benefit under this Plan in violation of this paragraph 15 shall be null and void.

16. *Adjustments*.

(a) The existence of outstanding Awards shall not affect in any manner the right or power of the Corporation or its stockholders to make or authorize any or all adjustments, recapitalizations, reorganizations or other changes in the capital stock of the Corporation or its business or any merger or consolidation of the Corporation, or any issue of bonds, debentures, preferred or prior preference stock (whether or not such issue is prior to, on a parity with or junior to the existing Common Stock) or the dissolution or liquidation of the Corporation, or any sale or transfer of all or any part of its assets or business, or any other corporate act or proceeding of any kind, whether or not of a character similar to that of the acts or proceedings enumerated above.

(b) In the event of any subdivision or consolidation of outstanding shares of Common Stock, declaration of a dividend payable in shares of Common Stock or other stock split, then (i) the number of shares of Common Stock reserved under this Plan, (ii) the number of shares of Common Stock covered by outstanding Awards, including, without limitation, Options, in the form of Common Stock or units denominated in Common Stock, (iii) the Grant Price or other price in respect of such Awards, (iv) the appropriate Fair Market Value and other price determinations for such Awards, and (v) the Stock Based Awards Limitations shall each be proportionately adjusted by the Board as appropriate to reflect such transaction. In the event of any other recapitalization or capital reorganization of the Corporation, any consolidation or merger of the Corporation with another corporation or entity, the adoption by the Corporation of any plan of exchange affecting Common Stock or any distribution to holders of Common Stock of securities or property (other than normal cash dividends or dividends payable in Common Stock), the Board shall make appropriate adjustments to (i) the number of shares of Common Stock covered by Awards, including, without limitation, Options, in the form of Common Stock or units denominated in Common Stock, (ii) the Grant Price or other price in respect of such Awards, (iii) the appropriate Fair Market Value and other price determinations for such Awards, and (iv) the Stock Based Awards Limitations to reflect such transaction; provided that such adjustments shall only be such as are necessary to maintain the proportionate interest of the holders of the Awards and preserve, without increasing, the value of such Awards.

(c) In the event of a corporate merger, consolidation, acquisition of property or stock, separation, reorganization or liquidation, the Board may make such adjustments to Awards or other provisions for the disposition of Awards as it deems equitable, and shall be authorized, in its discretion, (1) to provide for the substitution of a new Award or other arrangement (which, if applicable, may be exercisable for such property or stock as the Board determines) for an Award or the assumption of the Award, regardless of whether in a transaction to which Section 424(a) of the Code applies, (2) to provide, prior to the transaction, for the acceleration of the vesting and exercisability of, or lapse of restrictions with respect to, the Award and, if the transaction is a cash merger, provide for the termination of any portion of the Award that remains unexercised at the time of such transaction, or (3) to cancel any such Awards and to deliver to the Participants cash in an amount that the Board shall determine in its sole discretion is equal to the fair market value of such Awards on the date of such event, which in the case of Options or SARs shall be the excess of the Fair Market Value of Common Stock on such date over the Grant Price of such Award.

17. *Restrictions.* No Common Stock or other form of payment shall be issued with respect to any Award unless the Corporation shall be satisfied based on the advice of its counsel that such issuance will be in compliance with applicable federal and state securities laws. Certificates evidencing shares of Common Stock delivered under this Plan (to the extent that such shares are so evidenced) may be subject to such stop transfer orders and other restrictions as the Administrator may deem advisable under the rules, regulations and other requirements of the

Securities and Exchange Commission, any securities exchange or transaction reporting system upon which the Common Stock is then listed or to which it is admitted for quotation and any applicable federal or state securities law. The Administrator may cause a legend or legends to be placed upon such certificates (if any) to make appropriate reference to such restrictions.

18. *Unfunded Plan.* Insofar as it provides for Awards of cash, Common Stock or rights thereto, this Plan shall be unfunded. Although bookkeeping accounts may be established with respect to Participants who are entitled to cash, Common Stock or rights thereto under this Plan, any such accounts shall be used merely as a bookkeeping convenience. The Corporation shall not be required to segregate any assets that may at any time be represented by cash, Common Stock or rights thereto, nor shall this Plan be construed as providing for such segregation, nor shall the Corporation, the Board or the Committee be deemed to be a trustee of any cash, Common Stock or rights thereto to be granted under this Plan. Any liability or obligation of the Corporation to any Participant with respect to an Award of cash, Common Stock or rights thereto under this Plan shall be based solely upon any contractual obligations that may be created by this Plan and any Award Agreement, and no such liability or obligation of the Corporation shall be deemed to be secured by any pledge or other encumbrance on any property of the Corporation. Neither the Corporation nor the Board nor the Committee shall be required to give any security or bond for the performance of any obligation that may be created by this Plan.

19. *Section 409A of the Code*. It is intended that any Awards under the Plan satisfy the requirements of Section 409A of the Code to avoid imposition of applicable taxes thereunder. Thus, notwithstanding anything in this Plan to the contrary, if any Plan provision or Award under the Plan would result in the imposition of an applicable tax under Section 409A of the Code and related regulations and Treasury pronouncements, that Plan provision or Award will be reformed to avoid imposition of the applicable tax and no action taken to comply with Section 409A shall be deemed to adversely affect the Participant' s rights to an Award.

20. *Right to Employment.* Nothing in the Plan or an Award Agreement shall interfere with or limit in any way the right of the Corporation to terminate any Participant' s employment or other service relationship at any time, nor confer upon any Participant any right to continue in the capacity in which he or she is employed or otherwise serves the Corporation.

21. *Successors.* All obligations of the Corporation under the Plan with respect to Awards granted hereunder shall be binding on any successor to the Corporation, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation, or otherwise, of all or substantially all of the business and/or assets of the Corporation.

22. *Governing Law.* This Plan and all determinations made and actions taken pursuant hereto, to the extent not otherwise governed by mandatory provisions of the Code or the securities laws of the United States, shall be governed by and construed in accordance with the laws of the State of Texas.

23. *Effectiveness.* The Plan was approved by the Board on February 28, 2007. The Plan will be submitted to the stockholders of the Corporation for approval at the 2007 annual meeting of stockholders and, if approved, will become effective as of March 1, 2007. If the stockholders of the Corporation should fail to so approve this Plan at such meeting, this Plan shall terminate and cease to be of any further force or effect, and all grants of Awards hereunder, if any, shall be null and void.

Exhibit 10.6

MARATHON OIL CORPORATION
2007 INCENTIVE COMPENSATION PLAN
NONQUALIFIED STOCK OPTION AWARD AGREEMENT

[GRANT DATE]

Officer

Pursuant to this Award Agreement, MARATHON OIL CORPORATION (the "Corporation") hereby grants to **[NAME]** (the "Optionee"), an employee of the Corporation or a Subsidiary, on **[DATE]** (the "Grant Date"), a right (the "Option") to purchase from the Corporation **[NUMBER]** shares of Common Stock of the Corporation at a grant price of **$[PRICE]** per share (the "Grant Price"), pursuant to the Marathon Oil Corporation 2007 Incentive Compensation Plan (the "Plan"), with such number of shares and such price per share being subject to adjustment as provided in Section 16 of the Plan, and further subject to the following terms and conditions:

1. Relationship to the Plan. This Option is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations thereunder, if any, that have been adopted by the Committee. Except as defined herein (including in Paragraph 11 of this Award Agreement), capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Optionee also include the heirs or other legal representatives of the Optionee.

2. Exercise and Vesting Schedule.

(a) This Option shall become exercisable in three cumulative annual installments, as follows:

(i) one-third of the Option Shares shall become exercisable on the first anniversary of the Grant Date;

(ii) an additional one-third of the Option Shares shall become exercisable on the second anniversary of the Grant Date; and

(iii) the remaining one-third of the Option Shares shall become exercisable on the third anniversary of the Grant Date;

provided, however, that the Optionee must be in continuous Employment from the Grant Date through the date of exercisability of each installment in order for the Option to become exercisable with respect to additional shares of Common Stock on such date. If the Employment of the Optionee is terminated for any reason other than death or Retirement, any Option Shares that are not exercisable as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) This Option shall become fully exercisable, irrespective of the limitations set forth in subparagraph (a) above, upon:

(i) termination of the Optionee' s Employment due to death;

(ii) termination of the Optionee' s Employment due to Retirement; or

(ii) a Change in Control of the Corporation, provided that as of such Change in Control the Optionee had been in continuous Employment since the Grant Date.

3. Expiration of Option.

(a) Expiration of Option Period. The Option Period shall expire on the tenth anniversary of the Grant Date.

(b) Termination of Employment Due to Death or Retirement. If Employment of the Optionee is terminated due to death or Retirement, the Option shall expire upon the earlier of (i) five years following the date of termination of Employment or (ii) expiration of the Option Period. The death of the Optionee following Retirement but prior to the expiration of the Option shall have no effect on the expiration of the Option.

(c) Termination of Employment by the Corporation for Cause or Due to Resignation. If Employment of the Optionee is terminated by the Corporation or any of its Subsidiaries for Cause or due to voluntary resignation by the Optionee, the Option shall expire upon the termination of Employment.

(d) Termination of Employment by the Corporation Other Than For Cause. If Employment of the Optionee is terminated by the Corporation or any of its Affiliates for any reason other than Cause, the Option shall expire upon the earlier of (i) 90 days following the date of termination of Employment or (ii) expiration of the Option Period.

(e) Termination of Employment Following Change in Control. If Employment of the Optionee is terminated following a Change in Control and, as a result, the Optionee is eligible for severance benefits under a Change in Control Agreement, the Option shall remain exercisable throughout the Option Period.

4. Employment with a Competitor. Notwithstanding anything herein to the contrary, in the event the Committee, the Chief Executive Officer, or an authorized officer determines that the Optionee has accepted or intends to accept employment with a competitor of any business unit of the Corporation, the Committee, the Chief Executive Officer, or the authorized officer may cancel the Option by written notice to the Optionee.

5. Exercise of Option. Subject to the limitations set forth herein and in the Plan, this Option may be exercised in whole or in part by providing notice to the Committee or its designated representative of the number of Option Shares to be exercised. Such notice shall be accompanied by payment of the Grant Price of such Option Shares in cash or, at the election of the Optionee, in shares of Common Stock or any combination thereof. For purposes of determining the amount, if any, of the purchase price satisfied by payment in Common Stock, such Common Stock shall be valued at its Fair Market Value on the date of exercise. Upon receipt of the purchase price, the Corporation or its designated representative shall issue or cause to be issued to the Optionee a number of shares of Common Stock equal to the number of Option Shares then exercised.

6. Taxes. The Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise payable to the Optionee upon exercise of the Option or from compensation otherwise payable to the Optionee at the time of exercise pursuant to Section 13 of the Plan.

7. Shareholder Rights. The Optionee shall have no rights of a shareholder with respect to the Option Shares unless and until such time as the Option has been exercised and shares of Common Stock have been issued to the Optionee in conjunction with the exercise of the Option.

8. Nonassignability. During the Optionee' s lifetime, the Option may be exercised only by the Optionee or by the Optionee' s guardian or legal representative. Upon the Optionee' s death, the Option shall be transferred to the Optionee' s estate. Otherwise, the Optionee may not sell, transfer, assign, pledge or otherwise encumber any portion of the Option, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Option shall have no effect.

9. No Employment Guaranteed. Nothing in this Award Agreement shall give the Optionee any rights to (or impose any obligations for) continued Employment by the Corporation or any Affiliate thereof or successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Optionee.

10. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Optionee, adversely affect the rights of the Optionee hereunder.

11. Definitions. For purposes of this Award Agreement:

"**Cause**" means termination from Employment by the Corporation or its Subsidiaries due to unacceptable performance, gross misconduct, gross negligence, material dishonesty, material acts detrimental or destructive to the Corporation or its Subsidiaries, employees or property, or any material violation of the policies of the Corporation or its Subsidiaries.

"**Change in Control,**" unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a “Person”) is or becomes the “beneficial owner” (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation’ s then outstanding voting securities; provided, however, that for purposes of this Plan the term “Person” shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation’ s stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an “Excluded Transaction”) which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation’ s assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

“**Change in Control Agreement**” means any plan, program, agreement, or arrangement under which the Corporation or a Subsidiary agrees to provide benefits to the Optionee in the event he or she is terminated following a Change in Control, as applicable to the Optionee at the relevant time.

“**Employment**” means employment with the Corporation or any of its Affiliates. For purposes of this Option, Employment shall also include any period of time during which the Optionee is on Disability status.

“**Option Period**” means the period commencing upon the Optionee’ s receipt of this Award Agreement and ending on the date on which the Option expires pursuant to Paragraph 3(a).

“**Option Shares**” means the shares of Common Stock covered by this Option.

“**Retirement**” means (i) for an Employee participating in the Retirement Plans, termination on or after the time at which the Employee is eligible for retirement under the Retirement Plans, or (ii) for an Employee not participating in the Retirement Plans, (a) for an Employee with ten or more years of Employment, termination on or after the Employee’ s 50th birthday or (b) termination on or after the Employee’ s 65th birthday .

“**Retirement Plans**” means the Retirement Plan of Marathon Oil Company, the Marathon Petroleum Company LLC Retirement Plan, or a successor plan to either of such plans, as applicable.

Marathon Oil Corporation

By ________________________________

Authorized Officer

Exhibit 10.8

MARATHON OIL CORPORATION
2007 INCENTIVE COMPENSATION PLAN

OFFICER RESTRICTED STOCK AWARD AGREEMENT
[GRANT DATE]

Pursuant to this Award Agreement and the Marathon Oil Corporation 2007 Incentive Compensation Plan (the "Plan"), **MARATHON OIL CORPORATION** (the "Corporation") hereby grants to **[NAME]** (the "Participant"), an employee of the Corporation or a Subsidiary, on **[DATE]** (the "Grant Date"), **[NUMBER]** restricted shares of Common Stock ("Restricted Shares"). The number of Restricted Shares awarded is subject to adjustment as provided in Section 16 of the Plan, and the Restricted Shares are subject to the following terms and conditions:

1. Relationship to the Plan.

This grant of Restricted Shares is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations, if any, that have been adopted by the Committee. Except as defined in this Award Agreement (including in Paragraph 9 hereof), capitalized terms shall have the same meanings given to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan.

2. Vesting and Forfeiture of Restricted Shares.

The Restricted Shares shall vest on the third anniversary of the Grant Date; provided, however, that the Participant must be in continuous Employment from the Grant Date through the vesting date in order for the Restricted Shares to vest. If the Employment of the Participant is terminated for any reason (including non-Mandatory Retirement) other than death or Mandatory Retirement, any Restricted Shares that have not vested as of the date of such termination of Employment shall be forfeited to the Corporation.

(b) The Restricted Shares shall immediately vest in full, irrespective of the limitations set forth in subparagraph (a) above, upon:

(i) termination of the Participant' s Employment due to death;

(ii) termination of the Participant' s Employment due to Mandatory Retirement; or

(iii) a Change in Control of the Corporation, provided that as of such Change in Control the Participant has been in continuous Employment since the Grant Date.

3. Issuance of Shares. Effective as of the Grant Date, the Committee or its designated representative shall cause a number of shares of Common Stock equal to the number of Restricted Shares to be issued and registered in the Participant' s name, subject to the conditions and restrictions set forth in this Award Agreement and the Plan. Such issuance and registration shall be evidenced by an entry on the registry books of the Corporation and, if the Committee so elects, evidenced by a certificate issued by the Corporation. Any book entries and certificates evidencing the Restricted Shares shall carry or be endorsed with a legend referring to the conditions and restrictions set forth in this Award Agreement and the Plan. In the event the Restricted Shares are evidenced by a certificate, such certificate shall be held in custody by the Corporation unless and until the corresponding Restricted Shares are vested. The Participant shall not be entitled to delivery of a certificate or release of the restrictions on the book entry evidencing such Restricted Shares for any portion of the Restricted Shares unless and until the related Restricted Shares have vested pursuant to Paragraph 2. In the event the Restricted Shares are forfeited in full or in part, the Participant hereby consents to the relinquishment of the forfeited Restricted Shares theretofore issued and registered in the Participant' s name to the Corporation at that time.

4. Taxes. Pursuant to Section 13 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the shares of Common Stock otherwise deliverable to the Participant due to the vesting of Restricted Shares pursuant to Paragraph 2, or from other compensation payable to the Participant, at the time of the vesting and delivery of such shares.

5. Shareholder Rights. Unless and until the Restricted Shares are forfeited, the Participant shall have the rights of a shareholder with respect to the Restricted Shares as of the Grant Date, including the right to vote the Restricted Shares and the right to receive dividends. The Participant hereby consents to receiving any dividends on the unvested Restricted Shares through the Corporation' s payroll and, accordingly, directs the Corporation' s transfer agent to pay such dividends to the Corporation on his or her behalf.

6. Nonassignability. Upon the Participant' s death, the Restricted Shares shall be transferred to the Participant' s estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Restricted Shares, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Restricted Shares shall have no effect.

7. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Subsidiary or successor, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

8. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant.

9. Definitions. For purposes of this Award Agreement:

"**Change in Control,**" unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a "Person") is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation' s then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation' s stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

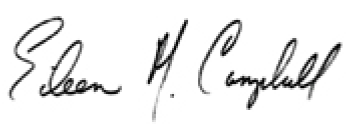
(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation' s assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

"**Employment**" means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

"**Mandatory Retirement**" means termination of Employment as a result of the Corporation' s policy, if any, requiring the mandatory retirement of officers and/or other employees upon reaching a certain age or milestone.

Marathon Oil Corporation



By ______________________________

Authorized Officer

Exhibit 10.10

MARATHON OIL CORPORATION
2007 INCENTIVE COMPENSATION PLAN

PERFORMANCE UNIT AWARD AGREEMENT
July 2011–December 2012 PERFORMANCE CYCLE

Section 16 Officer

Pursuant to this Award Agreement and the Marathon Oil Corporation 2007 Incentive Compensation Plan (the "Plan"), **MARATHON OIL CORPORATION** (the "Corporation") hereby grants to **[NAME]** (the "Participant"), an employee of the Corporation or a Subsidiary, on July 27, 2011, **[NUMBER]** performance units ("Performance Units"), conditioned upon the Corporation' s TSR Percentile Ranking for the July 2011 – December 2012 Performance Cycle. The Performance Units are subject to the following terms and conditions:

1. Relationship to the Plan.

This grant of Performance Units is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations thereunder, if any, that have been adopted by the Committee. Except as defined herein (including in Paragraph 14 of this Award Agreement), capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Participant also include the heirs or other legal representatives of the Participant.

2. Determination of Payout Percentage. As soon as practical following the close of the July 2011 – December 2012 Performance Cycle, the Committee shall determine the TSR Percentile Ranking. Thereafter, the Committee shall determine the Payout Percentage as follows:

(a) If the TSR Percentile Ranking is at or below the 25th percentile, the Payout Percentage shall be zero.

(b) If the TSR Percentile Ranking is above the 25th percentile, the Payout Percentage shall be equal to or less than the TSR Percentile Ranking multiplied by 2.

(c) Notwithstanding anything herein to the contrary, if the TSR calculated for the July 2011 – December 2012 Performance Cycle is negative, then the Payout Percentage shall not exceed 100%.

(d) Notwithstanding anything herein to the contrary, the Committee has sole and absolute authority and discretion to reduce the Payout Percentage as it may deem appropriate.

3. Vesting of Performance Units. Unless the Participant' s right to the Performance Units is previously forfeited or vested in accordance with Paragraphs 4, 5, 6, or 7, following the Committee' s determinations pursuant to Paragraph 2, the Participant shall vest in and be entitled to receive a cash payment equal to the product of (i) the number of Performance Units granted hereunder and (ii) the Payout Value. Such cash payment shall be made as soon as administratively feasible following the Committee' s determination under Paragraph 2 and, in any event, on or before March 15, 2013. If, in accordance with the Committee' s determination under Paragraph 2, the Payout Value is zero, the Participant shall immediately forfeit any and all rights to the Performance Units. Upon the vesting and/or forfeiture of the Performance Units pursuant to this Paragraph 3 and the making of the related cash payment, if any, the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be satisfied in full.

4. Termination of Employment. If Participant' s Employment is terminated prior to the close of the July 2011 – December 2012 Performance Cycle for any reason other than death or Retirement, the Participant' s right to the Performance Units shall be forfeited in its entirety as of such termination, and the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be terminated.

5. Termination of Employment due to Death. If Participant' s Employment is terminated by reason of death prior to the close of the July 2011 – December 2012 Performance Cycle, the Participant' s right to receive the Performance Units shall vest in full as of the date of death and the Payout Percentage shall be 100%. A cash payment equal to the vested value of the Performance Units shall be made in accordance with Paragraph 3 on the first day of the third month following the death of the Participant. Such vesting shall satisfy the rights of the Participant and the obligations of the Corporation under this Award Agreement in full.

6. Termination of Employment due to Retirement. In the event of the Retirement of the Participant on or after March 31, 2012, the Participant' s Performance Units may be considered for vesting following the close of the July 2011 – December 2012 Performance Cycle. At the discretion of the Committee, the Participant may vest in and be entitled to receive a cash payment equal to the product of (i) the percentage equal to the days of Participant' s Employment during the July 2011 – December 2012 Performance Cycle divided by the total days in the July 2011 – December 2012 Performance Cycle, (ii) the number of Performance Units granted hereunder, and (iii) the Payout Value. Such cash payment shall be made as soon as administratively feasible following the Committee' s determination under Paragraph 2 and, in any event, during the calendar year following the close of the July 2011 – December 2012 Performance Cycle. If, in accordance with the Committee' s determination under Paragraph 2, the Payout Value is zero, the Participant shall immediately forfeit any and all rights to the Performance Units. Upon the vesting and/or forfeiture of the Performance Units pursuant to this Paragraph 6 and the making of the related cash payment, if any, the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be satisfied in full. The death of the Participant following Retirement but prior to the close of the July 2011 – December 2012 Performance Cycle shall have no effect on this Paragraph 6.

7. Vesting Upon a Change of Control. Notwithstanding anything herein to the contrary, upon the occurrence of a Change in Control prior to the end of the July 2011 – December 2012 Performance Cycle, the Participant' s right to receive the Performance Units, unless previously forfeited pursuant to Paragraph 4, shall vest in full and the Payout Percentage shall be 100%. A cash payment equal to the vested value of the Performance Units shall be made in accordance with Paragraph 3 on the first day of the third month following the Change in Control. Such vesting shall satisfy the rights of the Participant and the obligations of the Corporation under this Award Agreement in full.

8. Repayment or Forfeiture Resulting from Forfeiture Event.

(a) If there is a Forfeiture Event either while the Participant is employed or within two years after termination of the Participant' s Employment, then the Committee may, but is not obligated to, cause some or all of the Participant' s outstanding Performance Units to be forfeited by the Participant.

(b) If there is a Forfeiture Event either while the Participant is employed or within two years after termination of the Participant' s Employment and a payment has previously been made in settlement of Performance Units granted under this Award Agreement, the Committee may, but is not obligated to, require that the Participant pay to the Corporation an amount (the "Forfeiture Amount") up to (but not in excess of) the amount paid in settlement of the Performance Units.

(c) This Paragraph 8 shall apply notwithstanding any provision of this Award Agreement to the contrary and is meant to provide the Corporation with rights in addition to any other remedy which may exist in law or in equity. This Paragraph 8 shall not apply to the Participant following the effective time of a Change in Control.

9. Taxes. Pursuant to Section 13 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the cash otherwise payable to the Participant, or from other compensation payable to the Participant, at the time of the vesting and delivery of such cash payment.

10. No Shareholder Rights. The Participant shall in no way be entitled to any of the rights of a shareholder as a result of this Award Agreement.

11. Nonassignability. Upon the Participant' s death, the Performance Units may be transferred by will or by the laws governing the descent and distribution of the Participant' s estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Performance Units, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Performance Units shall have no effect.

12. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Affiliate thereof or successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

13. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant hereunder.

14. Definitions. For purposes of this Award Agreement:

"**July 2011 – December 2012 Performance Cycle**" means the period from July 1, 2011 to December 31, 2012.

"**Beginning Stock Price**" means the average of the daily closing price of common stock for each trading day of July 2011, historically adjusted, if necessary, for any stock split, stock dividend, recapitalizations, or similar corporate events that occur during the measurement period.

"**Change in Control,**" unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a "Person") is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation' s then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation' s stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation' s assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

“**Cumulative Dividends**” means the sum of all cash dividends paid on a share of common stock during the July 2011 – December 2012 Performance Cycle. The Participant shall not be entitled to receive any dividend payments in conjunction with this award of Performance Units.

“**Employment**” means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

“**End Stock Price**” means the average of the daily closing price of common stock for each trading day of the calendar month ending on the last day of the July 2011 – December 2012 Performance Cycle.

“**Forfeiture Event**” means the occurrence of at least one of the following (a) the Corporation is required, pursuant to a determination made by the Securities and Exchange Commission or by the Audit Committee of the Board, to prepare a material accounting restatement due to the noncompliance of the Corporation with any financial reporting requirement under applicable securities laws as a result of misconduct, and the Committee determines that (1) the Participant knowingly engaged in the misconduct, (2) the Participant was grossly negligent with respect to such misconduct or (3) the Participant knowingly or grossly negligently failed to prevent the misconduct or (b) the Committee concludes that the Participant engaged in fraud, embezzlement or other similar misconduct materially detrimental to the Corporation.

“**Payout Percentage**” means the percentage (between 0% and 200%) determined by the Committee in accordance with the procedures set forth in Paragraph 2, which shall be used to determine the value of each Performance Unit.

“**Payout Value**” means, for each Performance Unit, the product of the Payout Percentage and $1.00.

“**Peer Group**” means the eleven companies (in addition to the Corporation) that are approved by the Compensation Committee of the Board and identified as peer companies at the time of grant of the Performance Units and which are still independent, publicly traded companies as of the last business day of the July 2011 – December 2012 Performance Cycle, or such other group of companies as selected by the Committee at its discretion.

“**Retirement**” means (i) for an Employee participating in the Retirement Plan, termination on or after the time at which the Employee is eligible for retirement under the Retirement Plan, or (ii) for an Employee not participating in the Retirement Plan, (a) for an Employee with ten or more years of Employment, termination on or after the Employee’ s 50th birthday or (b) termination on or after the Employee’ s 65th birthday.

"**Retirement Plan**" means the Retirement Plan of Marathon Oil Company or a successor plan to such plan, as applicable.

"**Total Shareholder Return**" **or** "**TSR**" means the number derived using the following formula:

$$\frac{\text{(End Stock Price – Beginning Stock Price) + Cumulative Dividends}}{\text{Beginning Stock Price.}}$$

"**TSR Percentile Ranking**" means the relative ranking of the Corporation's Total Shareholder Return for the July 2011 – December 2012 Performance Cycle as compared to the Total Shareholder Return of the Peer Group companies during the July 2011 – December 2012 Performance Cycle, expressed as a percentile ranking.

Marathon Oil Corporation

By ____________________________________

Authorized Officer

Exhibit 10.11

MARATHON OIL CORPORATION
2007 INCENTIVE COMPENSATION PLAN

PERFORMANCE UNIT AWARD AGREEMENT
July 2011−December 2012 PERFORMANCE CYCLE

Pursuant to this Award Agreement and the Marathon Oil Corporation 2007 Incentive Compensation Plan (the "Plan"), **MARATHON OIL CORPORATION** (the "Corporation") hereby grants to **[NAME]** (the "Participant"), an employee of the Corporation or a Subsidiary, on July 27, 2011, **[NUMBER]** performance units ("Performance Units"), conditioned upon the Corporation' s TSR Percentile Ranking for the July 2011 – December 2012 Performance Cycle. The Performance Units are subject to the following terms and conditions:

1. Relationship to the Plan.

This grant of Performance Units is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations thereunder, if any, that have been adopted by the Committee. Except as defined herein (including in Paragraph 13 of this Award Agreement), capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Participant also include the heirs or other legal representatives of the Participant.

2. Determination of Payout Percentage. As soon as practical following the close of the July 2011 – December 2012 Performance Cycle, the Committee shall determine the TSR Percentile Ranking. Thereafter, the Committee shall determine the Payout Percentage as follows:

(a) If the TSR Percentile Ranking is at or below the 25th percentile, the Payout Percentage shall be zero.

(b) If the TSR Percentile Ranking is above the 25th percentile, the Payout Percentage shall be equal to or less than the TSR Percentile Ranking multiplied by 2.

(c) Notwithstanding anything herein to the contrary, if the TSR calculated for the July 2011 – December 2012 Performance Cycle is negative, then the Payout Percentage shall not exceed 100%.

(d) Notwithstanding anything herein to the contrary, the Committee has sole and absolute authority and discretion to reduce the Payout Percentage as it may deem appropriate.

3. Vesting of Performance Units. Unless the Participant' s right to the Performance Units is previously forfeited or vested in accordance with Paragraphs 4, 5, 6, or 7, following the Committee' s determinations pursuant to Paragraph 2, the Participant shall vest in and be entitled to receive a cash payment equal to the product of (i) the number of Performance Units granted hereunder and (ii) the Payout Value. Such cash payment shall be made as soon as administratively feasible following the Committee' s determination under Paragraph 2 and, in any event, on or before March 15, 2013. If, in accordance with the Committee' s determination under Paragraph 2, the Payout Value is zero, the Participant shall immediately forfeit any and all rights to the Performance Units. Upon the vesting and/or forfeiture of the Performance Units pursuant to this Paragraph 3 and the making of the related cash payment, if any, the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be satisfied in full.

4. Termination of Employment. If Participant’ s Employment is terminated prior to the close of the July 2011 – December 2012 Performance Cycle for any reason other than death or Retirement, the Participant’ s right to the Performance Units shall be forfeited in its entirety as of such termination, and the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be terminated.

5. Termination of Employment due to Death. If Participant’ s Employment is terminated by reason of death prior to the close of the July 2011 – December 2012 Performance Cycle, the Participant’ s right to receive the Performance Units shall vest in full as of the date of death and the Payout Percentage shall be 100%. A cash payment equal to the vested value of the Performance Units shall be made in accordance with Paragraph 3 on the first day of the third month following the death of the Participant. Such vesting shall satisfy the rights of the Participant and the obligations of the Corporation under this Award Agreement in full.

6. Termination of Employment due to Retirement. In the event of the Retirement of the Participant on or after March 31, 2012, the Participant’ s Performance Units may be considered for vesting following the close of the July 2011 – December 2012 Performance Cycle. At the discretion of the Committee, the Participant may vest in and be entitled to receive a cash payment equal to the product of (i) the percentage equal to the days of Participant’ s Employment during the July 2011 – December 2012 Performance Cycle divided by the total days in the July 2011 – December 2012 Performance Cycle, (ii) the number of Performance Units granted hereunder, and (iii) the Payout Value. Such cash payment shall be made as soon as administratively feasible following the Committee’ s determination under Paragraph 2 and, in any event, during the calendar year following the close of the July 2011 – December 2012 Performance Cycle. If, in accordance with the Committee’ s determination under Paragraph 2, the Payout Value is zero, the Participant shall immediately forfeit any and all rights to the Performance Units. Upon the vesting and/or forfeiture of the Performance Units pursuant to this Paragraph 6 and the making of the related cash payment, if any, the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be satisfied in full. The death of the Participant following Retirement but prior to the close of the July 2011 – December 2012 Performance Cycle shall have no effect on this Paragraph 6.

7. Vesting Upon a Change of Control. Notwithstanding anything herein to the contrary, upon the occurrence of a Change in Control prior to the end of the July 2011 – December 2012 Performance Cycle, the Participant’ s right to receive the Performance Units, unless previously forfeited pursuant to Paragraph 4, shall vest in full and the Payout Percentage shall be 100%. A cash payment equal to the vested value of the Performance Units shall be made in accordance with Paragraph 3 on the first day of the third month following the Change in Control. Such vesting shall satisfy the rights of the Participant and the obligations of the Corporation under this Award Agreement in full.

8. Taxes. Pursuant to Section 13 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the cash otherwise payable to the Participant, or from other compensation payable to the Participant, at the time of the vesting and delivery of such cash payment.

9. No Shareholder Rights. The Participant shall in no way be entitled to any of the rights of a shareholder as a result of this Award Agreement.

10. Nonassignability. Upon the Participant' s death, the Performance Units may be transferred by will or by the laws governing the descent and distribution of the Participant' s estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Performance Units, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Performance Units shall have no effect.

11. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Affiliate thereof or successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

12. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant hereunder.

13. Definitions. For purposes of this Award Agreement:

"**July 2011 – December 2012 Performance Cycle**" means the period from July 1, 2011 to December 31, 2012.

"**Beginning Stock Price**" means the average of the daily closing price of common stock for each trading day of July 2011, historically adjusted, if necessary, for any stock split, stock dividend, recapitalizations, or similar corporate events that occur during the measurement period.

"**Change in Control,**" unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a "Person") is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation' s then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation' s stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation' s assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

"**Cumulative Dividends**" means the sum of all cash dividends paid on a share of common stock during the July 2011 – December 2012 Performance Cycle. The Participant shall not be entitled to receive any dividend payments in conjunction with this award of Performance Units.

"**Employment**" means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

"**End Stock Price**" means the average of the daily closing price of common stock for each trading day of the calendar month ending on the last day of the July 2011 – December 2012 Performance Cycle.

"**Payout Percentage**" means the percentage (between 0% and 200%) determined by the Committee in accordance with the procedures set forth in Paragraph 2, which shall be used to determine the value of each Performance Unit.

"**Payout Value**" means, for each Performance Unit, the product of the Payout Percentage and $1.00.

"**Peer Group**" means the eleven companies (in addition to the Corporation) that are are approved by the Compensation Committee of the Board and identified as peer companies at the time of grant of the Performance Units and which are still independent, publicly traded companies as of the last business day of the July 2011 – December 2012 Performance Cycle, or such other group of companies as selected by the Committee at its discretion.

"**Retirement**" means (i) for an Employee participating in the Retirement Plan, termination on or after the time at which the Employee is eligible for retirement under the Retirement Plan, or (ii) for an Employee not participating in the Retirement Plan, (a) for an Employee with ten or more years of Employment, termination on or after the Employee' s 50th birthday or (b) termination on or after the Employee' s 65th birthday.

"**Retirement Plan**" means the Retirement Plan of Marathon Oil Company, or a successor plan to such plan, as applicable.

"**Total Shareholder Return" or "TSR**" means the number derived using the following formula:

$$\frac{\text{(End Stock Price – Beginning Stock Price) + Cumulative Dividends}}{\text{Beginning Stock Price}}.$$

"**TSR Percentile Ranking**" means the relative ranking of the Corporation' s Total Shareholder Return for the July 2011 – December 2012 Performance Cycle as compared to the Total Shareholder Return of the Peer Group companies during the July 2011 – December 2012 Performance Cycle, expressed as a percentile ranking.

Marathon Oil Corporation

By ____________________________
Authorized Officer

Exhibit 10.12

MARATHON OIL CORPORATION
2007 INCENTIVE COMPENSATION PLAN

PERFORMANCE UNIT AWARD AGREEMENT
July 2011−December 2013 PERFORMANCE CYCLE

Section 16 Officer

Pursuant to this Award Agreement and the Marathon Oil Corporation 2007 Incentive Compensation Plan (the "Plan"), **MARATHON OIL CORPORATION** (the "Corporation") hereby grants to **[NAME]** (the "Participant"), an employee of the Corporation or a Subsidiary, on July 27, 2011, **[NUMBER]** performance units ("Performance Units"), conditioned upon the Corporation' s TSR Percentile Ranking for the July 2011 – December 2013 Performance Cycle. The Performance Units are subject to the following terms and conditions:

1. Relationship to the Plan.

This grant of Performance Units is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations thereunder, if any, that have been adopted by the Committee. Except as defined herein (including in Paragraph 14 of this Award Agreement), capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Participant also include the heirs or other legal representatives of the Participant.

2. Determination of Payout Percentage. As soon as practical following the close of the July 2011 – December 2013 Performance Cycle, the Committee shall determine the TSR Percentile Ranking. Thereafter, the Committee shall determine the Payout Percentage as follows:

(a) If the TSR Percentile Ranking is at or below the 25^{th} percentile, the Payout Percentage shall be zero.

(b) If the TSR Percentile Ranking is above the 25^{th} percentile, the Payout Percentage shall be equal to or less than the TSR Percentile Ranking multiplied by 2.

(c) Notwithstanding anything herein to the contrary, if the TSR calculated for the July 2011 – December 2013 Performance Cycle is negative, then the Payout Percentage shall not exceed 100%.

(d) Notwithstanding anything herein to the contrary, the Committee has sole and absolute authority and discretion to reduce the Payout Percentage as it may deem appropriate.

3. Vesting of Performance Units. Unless the Participant' s right to the Performance Units is previously forfeited or vested in accordance with Paragraphs 4, 5, 6, or 7, following the Committee' s determinations pursuant to Paragraph 2, the Participant shall vest in and be entitled to receive a cash payment equal to the product of (i) the number of Performance Units granted hereunder and (ii) the Payout Value. Such cash payment shall be made as soon as administratively feasible following the Committee' s determination under Paragraph 2 and, in any event, on or before March 15, 2014. If, in accordance with the Committee' s determination under Paragraph 2, the Payout Value is zero, the Participant shall immediately forfeit any and all rights to the Performance Units. Upon the vesting and/or forfeiture of the Performance Units pursuant to this Paragraph 3 and the making of the related cash payment, if any, the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be satisfied in full.

4. Termination of Employment. If Participant' s Employment is terminated prior to the close of the July 2011 – December 2013 Performance Cycle for any reason other than death or Retirement, the Participant' s right to the Performance Units shall be forfeited in its entirety as of such termination, and the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be terminated.

5. Termination of Employment due to Death. If Participant' s Employment is terminated by reason of death prior to the close of the July 2011 – December 2013 Performance Cycle, the Participant' s right to receive the Performance Units shall vest in full as of the date of death and the Payout Percentage shall be 100%. A cash payment equal to the vested value of the Performance Units shall be made in accordance with Paragraph 3 on the first day of the third month following the death of the Participant. Such vesting shall satisfy the rights of the Participant and the obligations of the Corporation under this Award Agreement in full.

6. Termination of Employment due to Retirement. In the event of the Retirement of the Participant on or after September 30, 2012, the Participant' s Performance Units may be considered for vesting following the close of the July 2011 – December 2013 Performance Cycle. At the discretion of the Committee, the Participant may vest in and be entitled to receive a cash payment equal to the product of (i) the percentage equal to the days of Participant' s Employment during the July 2011 – December 2013 Performance Cycle divided by the total days in the July 2011 – December 2013 Performance Cycle, (ii) the number of Performance Units granted hereunder, and (iii) the Payout Value. Such cash payment shall be made as soon as administratively feasible following the Committee' s determination under Paragraph 2 and, in any event, during the calendar year following the close of the July 2011 – December 2013 Performance Cycle. If, in accordance with the Committee' s determination under Paragraph 2, the Payout Value is zero, the Participant shall immediately forfeit any and all rights to the Performance Units. Upon the vesting and/or forfeiture of the Performance Units pursuant to this Paragraph 6 and the making of the related cash payment, if any, the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be satisfied in full. The death of the Participant following Retirement but prior to the close of the July 2011 – December 2013 Performance Cycle shall have no effect on this Paragraph 6.

7. Vesting Upon a Change of Control. Notwithstanding anything herein to the contrary, upon the occurrence of a Change in Control prior to the end of the July 2011 – December 2013 Performance Cycle, the Participant' s right to receive the Performance Units, unless previously forfeited pursuant to Paragraph 4, shall vest in full and the Payout Percentage shall be 100%. A cash payment equal to the vested value of the Performance Units shall be made in accordance with Paragraph 3 on the first day of the third month following the Change in Control. Such vesting shall satisfy the rights of the Participant and the obligations of the Corporation under this Award Agreement in full.

8. Repayment or Forfeiture Resulting from Forfeiture Event.

(a) If there is a Forfeiture Event either while the Participant is employed or within two years after termination of the Participant' s Employment, then the Committee may, but is not obligated to, cause some or all of the Participant' s outstanding Performance Units to be forfeited by the Participant.

(b) If there is a Forfeiture Event either while the Participant is employed or within two years after termination of the Participant' s Employment and a payment has previously been made in settlement of Performance Units granted under this Award Agreement, the Committee may, but is not obligated to, require that the Participant pay to the Corporation an amount (the "Forfeiture Amount") up to (but not in excess of) the amount paid in settlement of the Performance Units.

(c) This Paragraph 8 shall apply notwithstanding any provision of this Award Agreement to the contrary and is meant to provide the Corporation with rights in addition to any other remedy which may exist in law or in equity. This Paragraph 8 shall not apply to the Participant following the effective time of a Change in Control.

9. Taxes. Pursuant to Section 13 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the cash otherwise payable to the Participant, or from other compensation payable to the Participant, at the time of the vesting and delivery of such cash payment.

10. No Shareholder Rights. The Participant shall in no way be entitled to any of the rights of a shareholder as a result of this Award Agreement.

11. Nonassignability. Upon the Participant' s death, the Performance Units may be transferred by will or by the laws governing the descent and distribution of the Participant' s estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Performance Units, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Performance Units shall have no effect.

12. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Affiliate thereof or successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

13. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant hereunder.

14. Definitions. For purposes of this Award Agreement:

"**July 2011 – December 2013 Performance Cycle**" means the period from July 1, 2011 to December 31, 2013.

"**Beginning Stock Price**" means the average of the daily closing price of common stock for each trading day of July 2011, historically adjusted, if necessary, for any stock split, stock dividend, recapitalizations, or similar corporate events that occur during the measurement period.

"**Change in Control,**" unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a "Person") is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation' s then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation' s stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation' s assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

“**Cumulative Dividends**” means the sum of all cash dividends paid on a share of common stock during the July 2011 – December 2013 Performance Cycle. The Participant shall not be entitled to receive any dividend payments in conjunction with this award of Performance Units.

“**Employment**” means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

“**End Stock Price**” means the average of the daily closing price of common stock for each trading day of the calendar month ending on the last day of the July 2011 – December 2013 Performance Cycle.

“**Forfeiture Event**” means the occurrence of at least one of the following (a) the Corporation is required, pursuant to a determination made by the Securities and Exchange Commission or by the Audit Committee of the Board, to prepare a material accounting restatement due to the noncompliance of the Corporation with any financial reporting requirement under applicable securities laws as a result of misconduct, and the Committee determines that (1) the Participant knowingly engaged in the misconduct, (2) the Participant was grossly negligent with respect to such misconduct or (3) the Participant knowingly or grossly negligently failed to prevent the misconduct or (b) the Committee concludes that the Participant engaged in fraud, embezzlement or other similar misconduct materially detrimental to the Corporation.

“**Payout Percentage**” means the percentage (between 0% and 200%) determined by the Committee in accordance with the procedures set forth in Paragraph 2, which shall be used to determine the value of each Performance Unit.

“**Payout Value**” means, for each Performance Unit, the product of the Payout Percentage and $1.00.

“**Peer Group**” means the eleven companies (in addition to the Corporation) that are approved by the Compensation Committee of the Board and identified as peer companies at the time of grant of the Performance Units and which are still independent, publicly traded companies as of the last business day of the July 2011 – December 2013 Performance Cycle, or such other group of companies as selected by the Committee at its discretion.

“**Retirement**” means (i) for an Employee participating in the Retirement Plan, termination on or after the time at which the Employee is eligible for retirement under the Retirement Plan, or (ii) for an Employee not participating in the Retirement Plan, (a) for an Employee with ten or more years of Employment, termination on or after the Employee’ s 50th birthday or (b) termination on or after the Employee’ s 65th birthday.

“**Retirement Plan**” means the Retirement Plan of Marathon Oil Company or a successor plan to such plan, as applicable.

“**Total Shareholder Return**” **or** “**TSR**” means the number derived using the following formula:

$$\frac{\text{(End Stock Price} - \text{Beginning Stock Price)} + \text{Cumulative Dividends}}{\text{Beginning Stock Price.}}$$

“**TSR Percentile Ranking**” means the relative ranking of the Corporation’ s Total Shareholder Return for the July 2011 – December 2013 Performance Cycle as compared to the Total Shareholder Return of the Peer Group companies during the July 2011 – December 2013 Performance Cycle, expressed as a percentile ranking.

Marathon Oil Corporation

By ________________________________

Authorized Officer

Exhibit 10.13

MARATHON OIL CORPORATION
2007 INCENTIVE COMPENSATION PLAN

PERFORMANCE UNIT AWARD AGREEMENT
July 2011 - December 2013 PERFORMANCE CYCLE

Pursuant to this Award Agreement and the Marathon Oil Corporation 2007 Incentive Compensation Plan (the "Plan"), **MARATHON OIL CORPORATION** (the "Corporation") hereby grants to **[NAME]** (the "Participant"), an employee of the Corporation or a Subsidiary, on July 27, 2011, **[NUMBER]** performance units ("Performance Units"), conditioned upon the Corporation' s TSR Percentile Ranking for the July 2011 – December 2013 Performance Cycle. The Performance Units are subject to the following terms and conditions:

1. Relationship to the Plan.

This grant of Performance Units is subject to all of the terms, conditions and provisions of the Plan and administrative interpretations thereunder, if any, that have been adopted by the Committee. Except as defined herein (including in Paragraph 13 of this Award Agreement), capitalized terms shall have the same meanings ascribed to them under the Plan. To the extent that any provision of this Award Agreement conflicts with the express terms of the Plan, the terms of the Plan shall control and, if necessary, the applicable provisions of this Award Agreement shall be hereby deemed amended so as to carry out the purpose and intent of the Plan. References to the Participant also include the heirs or other legal representatives of the Participant.

2. Determination of Payout Percentage. As soon as practical following the close of the July 2011 – December 2013 Performance Cycle, the Committee shall determine the TSR Percentile Ranking. Thereafter, the Committee shall determine the Payout Percentage as follows:

(a) If the TSR Percentile Ranking is at or below the 25^{th} percentile, the Payout Percentage shall be zero.

(b) If the TSR Percentile Ranking is above the 25^{th} percentile, the Payout Percentage shall be equal to or less than the TSR Percentile Ranking multiplied by 2.

(c) Notwithstanding anything herein to the contrary, if the TSR calculated for the July 2011 – December 2013 Performance Cycle is negative, then the Payout Percentage shall not exceed 100%.

(d) Notwithstanding anything herein to the contrary, the Committee has sole and absolute authority and discretion to reduce the Payout Percentage as it may deem appropriate.

3. Vesting of Performance Units. Unless the Participant' s right to the Performance Units is previously forfeited or vested in accordance with Paragraphs 4, 5, 6, or 7, following the Committee' s determinations pursuant to Paragraph 2, the Participant shall vest in and be entitled to receive a cash payment equal to the product of (i) the number of Performance Units granted hereunder and (ii) the Payout Value. Such cash payment shall be made as soon as administratively feasible following the Committee' s determination under Paragraph 2 and, in any event, on or before March 15, 2014. If, in accordance with the Committee' s determination under Paragraph 2, the Payout Value is zero, the Participant shall immediately forfeit any and all rights to the Performance Units. Upon the vesting and/or forfeiture of the Performance Units pursuant to this Paragraph 3 and the making of the related cash payment, if any, the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be satisfied in full.

4. Termination of Employment. If Participant' s Employment is terminated prior to the close of the July 2011 – December 2013 Performance Cycle for any reason other than death or Retirement, the Participant' s right to the Performance Units shall be forfeited in its entirety as of such termination, and the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be terminated.

5. Termination of Employment due to Death. If Participant' s Employment is terminated by reason of death prior to the close of the July 2011 – December 2013 Performance Cycle, the Participant' s right to receive the Performance Units shall vest in full as of the date of death and the Payout Percentage shall be 100%. A cash payment equal to the vested value of the Performance Units shall be made in accordance with Paragraph 3 on the first day of the third month following the death of the Participant. Such vesting shall satisfy the rights of the Participant and the obligations of the Corporation under this Award Agreement in full.

6. Termination of Employment due to Retirement. In the event of the Retirement of the Participant on or after September 30, 2012, the Participant' s Performance Units may be considered for vesting following the close of the July 2011 – December 2013 Performance Cycle. At the discretion of the Committee, the Participant may vest in and be entitled to receive a cash payment equal to the product of (i) the percentage equal to the days of Participant' s Employment during the July 2011 – December 2013 Performance Cycle divided by the total days in the July 2011 – December 2013 Performance Cycle, (ii) the number of Performance Units granted hereunder, and (iii) the Payout Value. Such cash payment shall be made as soon as administratively feasible following the Committee' s determination under Paragraph 2 and, in any event, during the calendar year following the close of the July 2011 – December 2013 Performance Cycle. If, in accordance with the Committee' s determination under Paragraph 2, the Payout Value is zero, the Participant shall immediately forfeit any and all rights to the Performance Units. Upon the vesting and/or forfeiture of the Performance Units pursuant to this Paragraph 6 and the making of the related cash payment, if any, the rights of the Participant and the obligations of the Corporation under this Award Agreement shall be satisfied in full. The death of the Participant following Retirement but prior to the close of the July 2011 – December 2013 Performance Cycle shall have no effect on this Paragraph 6.

7. Vesting Upon a Change of Control. Notwithstanding anything herein to the contrary, upon the occurrence of a Change in Control prior to the end of the July 2011 – December 2013 Performance Cycle, the Participant' s right to receive the Performance Units, unless previously forfeited pursuant to Paragraph 4, shall vest in full and the Payout Percentage shall be 100%. A cash payment equal to the vested value of the Performance Units shall be made in accordance with Paragraph 3 on the first day of the third month following the Change in Control. Such vesting shall satisfy the rights of the Participant and the obligations of the Corporation under this Award Agreement in full.

8. Taxes. Pursuant to Section 13 of the Plan, the Corporation or its designated representative shall have the right to withhold applicable taxes from the cash otherwise payable to the Participant, or from other compensation payable to the Participant, at the time of the vesting and delivery of such cash payment.

9. No Shareholder Rights. The Participant shall in no way be entitled to any of the rights of a shareholder as a result of this Award Agreement.

10. Nonassignability. Upon the Participant' s death, the Performance Units may be transferred by will or by the laws governing the descent and distribution of the Participant' s estate. Otherwise, the Participant may not sell, transfer, assign, pledge or otherwise encumber any portion of the Performance Units, and any attempt to sell, transfer, assign, pledge, or encumber any portion of the Performance Units shall have no effect.

11. No Employment Guaranteed. Nothing in this Award Agreement shall give the Participant any rights to (or impose any obligations for) continued Employment by the Corporation or any Affiliate thereof or successor thereto, nor shall it give such entities any rights (or impose any obligations) with respect to continued performance of duties by the Participant.

12. Modification of Agreement. Any modification of this Award Agreement shall be binding only if evidenced in writing and signed by an authorized representative of the Corporation, provided that no modification may, without the consent of the Participant, adversely affect the rights of the Participant hereunder.

13. Definitions. For purposes of this Award Agreement:

"**July 2011 – December 2013 Performance Cycle**" means the period from July 1, 2011 to December 31, 2013.

"**Beginning Stock Price**" means the average of the daily closing price of common stock for each trading day of July 2011, historically adjusted, if necessary, for any stock split, stock dividend, recapitalizations, or similar corporate events that occur during the measurement period.

"**Change in Control,**" unless otherwise defined by the Committee, means a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended, whether or not the Corporation is then subject to such reporting requirement; provided, that, without limitation, such a change in control shall be deemed to have occurred if:

(i) any person (as defined in Sections 13(d) and 14(d) of the Exchange Act) (a "Person") is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Corporation (not including in the amount of the securities beneficially owned by such person any such securities acquired directly from the Corporation or its affiliates) representing twenty percent (20%) or more of the combined voting power of the Corporation' s then outstanding voting securities; provided, however, that for purposes of this Plan the term "Person" shall not include (A) the Corporation or any of its subsidiaries, (B) a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any of its subsidiaries, (C) an underwriter temporarily holding securities pursuant to an offering of such securities, or (D) a corporation owned, directly or indirectly, by the stockholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation; and provided, further, however, that for purposes of this paragraph (i), there shall be excluded any Person who becomes such a beneficial owner in connection with an Excluded Transaction (as defined in paragraph (iii) below);

(ii) the following individuals cease for any reason to constitute a majority of the number of Directors then serving: individuals who, on the date hereof, constitute the Board and any new Director (other than a Director whose initial assumption of office is in connection with an actual or threatened election contest including but not limited to a consent solicitation, relating to the election of Directors of the Corporation) whose appointment or election by the Board or nomination for election by the Corporation' s stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were Directors on the date hereof or whose appointment, election or nomination for election was previously so approved; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect subsidiary thereof with any other corporation, other than a merger or consolidation (an "Excluded Transaction") which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving corporation or any parent thereof) at least 50% of the combined voting power of the voting securities of the entity surviving the merger or consolidation (or the parent of such surviving entity) immediately after such merger or consolidation, or the stockholders of the Corporation approve a plan of complete liquidation of the Corporation, or there is consummated the sale or other disposition of all or substantially all of the Corporation' s assets.

Notwithstanding any other provision to the contrary, in no event shall the transfer of ownership interests in the Corporation in and of itself constitute a Change in Control under this Award Agreement.

"**Cumulative Dividends**" means the sum of all cash dividends paid on a share of common stock during the July 2011 – December 2013 Performance Cycle. The Participant shall not be entitled to receive any dividend payments in conjunction with this award of Performance Units.

"**Employment**" means employment with the Corporation or any of its Subsidiaries. For purposes of this Award Agreement, Employment shall also include any period of time during which the Participant is on Disability status.

"**End Stock Price**" means the average of the daily closing price of common stock for each trading day of the calendar month ending on the last day of the July 2011 – December 2013 Performance Cycle.

"**Payout Percentage**" means the percentage (between 0% and 200%) determined by the Committee in accordance with the procedures set forth in Paragraph 2, which shall be used to determine the value of each Performance Unit.

"**Payout Value**" means, for each Performance Unit, the product of the Payout Percentage and $1.00.

"**Peer Group**" means the eleven companies (in addition to the Corporation) that are are approved by the Compensation Committee of the Board and identified as peer companies at the time of grant of the Performance Units and which are still independent, publicly traded companies as of the last business day of the July 2011 – December 2013 Performance Cycle, or such other group of companies as selected by the Committee at its discretion.

"**Retirement**" means (i) for an Employee participating in the Retirement Plan, termination on or after the time at which the Employee is eligible for retirement under the Retirement Plan, or (ii) for an Employee not participating in the Retirement Plan, (a) for an Employee with ten or more years of Employment, termination on or after the Employee' s 50th birthday or (b) termination on or after the Employee' s 65th birthday.

"**Retirement Plan**" means the Retirement Plan of Marathon Oil Company, or a successor plan to such plan, as applicable.

"**Total Shareholder Return**" **or** "**TSR**" means the number derived using the following formula:

$$\frac{\text{(End Stock Price – Beginning Stock Price) + Cumulative Dividends}}{\text{Beginning Stock Price.}}$$

"**TSR Percentile Ranking**" means the relative ranking of the Corporation' s Total Shareholder Return for the July 2011 – December 2013 Performance Cycle as compared to the Total Shareholder Return of the Peer Group companies during the July 2011 – December 2013 Performance Cycle, expressed as a percentile ranking.

Marathon Oil Corporation

By ______________________________

Authorized Officer

Exhibit 10.31

MARATHON OIL COMPANY

EXCESS BENEFIT PLAN

Amended and Restated As Of

The

Distribution Date

EXCESS BENEFIT PLAN

ARTICLE I. Purpose

On February 5, 1976, the Board of Directors of the former Marathon Oil Company (now named "Marathon Oil Company") resolved, effective January 1, 1976, to compensate employees for the loss of benefits under the Retirement Plan and the loss of Company contributions to the Thrift Plan that occur due to the limits placed by the Code on benefits payable and contributions permitted under qualified plans. On the date of that resolution, the only limits placed by the Code were those contained in Code section 415. Accordingly, this Excess Benefit Plan was created.

On May 6, 1982, the former Marathon Oil Company adopted a Plan of Partial Liquidation. Pursuant to the Plan of Partial Liquidation and an Agreement for Implementation of Plan of Partial Liquidation dated July 10, 1982, Marathon Oil Company (formerly "USS Holdings Company, Inc.") assumed all of the obligations, terms, and conditions of the Retirement Plan, Thrift Plan, and this Excess Benefit Plan.

On July 5, 1988, the Executive Committee of the Board of Directors of the Company approved amendments to this Excess Benefit Plan effective January 1, 1988, designed to compensate employees for the loss of benefits under the Retirement Plan and the Thrift Plan due to certain additional limitations on benefits payable under qualified plans and contributions permitted under qualified plans which were added to the Code by the Tax Reform Act of 1986. These limitations include Code section 415, Code section 401(k), Code section 401(m), Code section 402(g), and Code section 401(a)(17).

Effective January 1, 2006, this Excess Benefit Plan was restated to incorporate prior amendments.

Effective January 1, 2009, this Excess Benefit Plan was restated and shall apply only to benefits that are not fully distributed as of such date, including both 409A Accruals and Grandfathered Accruals. With respect to the 409A Accruals, the Excess Benefit Plan, as amended and restated, is intended to conform to the requirements of Code section 409A, and, in all respects, shall be administered and construed in accordance with such requirements. With respect to the Grandfathered Accruals, the Excess Benefit Plan, as amended and restated, does not represent a material enhancement of the benefits or rights available under the Excess Benefit Plan on October 3, 2004.

Effective on the Distribution Date, this Excess Benefit Plan is restated to provide for the allocation of liabilities between this Excess Benefit Plan and the corresponding excess benefit plans for employees of Marathon Petroleum Corporation and Speedway LLC in accordance with the Employee Matters Agreement and to provide the Select Group Members with a Final Average Pay adjustment for their Legacy Retirement Benefit which corresponds to the Final Average Pay adjustment made available under the Retirement Plan to other Members for their Legacy Retirement Benefit.

This Excess Benefit Plan sets forth the terms and conditions under which benefits designed to compensate Employees for the aforementioned losses of benefits shall be accrued and paid by the applicable Employer. Capitalized terms, unless otherwise specified, are defined under the Retirement Plan and the Thrift Plan and the Employee Matters Agreement. In addition, for purposes of this Article I and the remainder of this Excess Benefit Plan, the following definitions apply:

"**409A Accruals**" means those benefits that were accrued after or became vested after 2004, as adjusted for interest or changes in present value, as applicable. Such amounts shall be determined in accordance with Code section 409A.

"**Code**" means the Internal Revenue Code.

"**Code section 409A**" means section 409A of the Code and any Treasury and Internal Revenue Service regulations and guidance issued thereunder.

"**Company**" means Marathon Oil Company.

"Distribution Agreement" means the Separation and Distribution Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Oil Company and Marathon Petroleum Corporation.

"Distribution Date" means the Distribution Date as defined in the Distribution Agreement.

"**Employee**" means any individual employed by an Employer.

"Employee Matters Agreement" means the agreement respecting certain employee matters dated May 25, 2011 between Marathon Oil Corporation and Marathon Petroleum Corporation.

"**Employer**" includes the Company and each related company or business which is part of the same controlled group under Code sections 414(b) or 414(c); provided that where specified by the Employer in accordance with Code section 409A in applying Code section 1563(a)(1) - (a)(3) for purposes of determining a controlled group of corporations under Code section 414(b) and in applying Treasury Regulation section 1.414(c)-2 for purposes of determining whether trades or businesses are under common control under Code section 414(c), the phrase "at least 50 percent" is used instead of "at least 80 percent." In addition, the term "Employer" shall also include any entity that previously met the requirements of an "Employer" as set forth herein that continues to employ a Participant to the extent so designated by the Plan Administrator.

"**Excess Benefit Plan**" means the Marathon Oil Company Excess Benefit Plan.

"**Grandfathered Accruals**" means those benefits that are exempt from Code section 409A because they were accrued and vested before January 1, 2005, as adjusted for interest or changes in present value, as applicable. Such amounts shall be determined in accordance with Code section 409A.

"**Retirement Plan**" means the Retirement Plan of Marathon Oil Company.

"Select Group Member" means a Member of the Retirement Plan who, on August 17, 2009, either was a supervisor in Grade 14 or above or had base pay of $190,000 (specifically excluding bonus) or higher.

"**Separation from Service**" shall have the same meaning as set forth under Code section 409A with respect to an Employer.

"**Specified Employee**" shall have the meaning as set forth under Code section 409A and as determined by the Employer in accordance with its established policy.

"**Thrift Plan**" means the Marathon Oil Company Thrift Plan.

ARTICLE II. Eligibility

2.1 Eligibility for Benefits

The following individuals are eligible to accrue Excess Benefit Plan benefits:

(a) (1) Every individual who qualifies for a benefit under the terms of the Retirement Plan and (i) whose benefit as determined under Article V, Section A, or B and C, of the Retirement Plan is reduced due to salary deferrals under the Marathon Oil Company Deferred Compensation Plan or any similar plan maintained by the Employer or by either Code section 415 or the annual compensation limit as set forth under Code section 401(a)(17) (collectively, the "Defined Benefit Limits"), or (ii) would accrue a Special Excess Bonus Recognition benefit as set forth in section 3.1(b) hereof and is designated by the Plan Administrator and (2) each Select Group Member whose Legacy Retirement Benefit under the Retirement Plan is determined without taking into account his or her changes in Final Average Pay after December 31, 2009.

(b) Every individual who participates in the Thrift Plan and who (i) has potential contributions to the Thrift Plan limited by Code Requirements (as defined below) to a point which precludes the individual' s receipt of the maximum matching Company Contributions provided under Article VI of the Thrift Plan; (ii) is limited by IRC Requirements to making contributions to the Thrift Plan at a percentage that is less than their elected contribution percentage; and (iii) continues to make After-Tax and MSP Contributions to the Thrift Plan at the maximum rate as limited by Code requirements. As used in this Excess Benefit Plan, the term "IRC Requirements" includes, and is limited to, the following requirements:

(1) Code section 415;

(2) Code section 401(k) (Actual Deferral Percentage test) and Code section 401(m) (Actual Contribution Percentage test);

(3) The Code section 402(g) annual dollar limitation on MSP Contributions; or

(4) The annual compensation limit as set forth under Code section 401(a)(17).

Every individual who is eligible to receive benefits under this Excess Benefit Plan by reason of his or her active employment with an Employer shall be known as a Participant. Every individual who becomes eligible to receive benefits under this Excess Benefit Plan in the event of the death of a Participant shall be known as a Beneficiary. The Beneficiary of a Participant under this Excess Benefit Plan shall be such Beneficiary as may be provided under Section 3.3(b).

2.2 No Duplication of Benefits

Any individual who is eligible under the terms of the Marathon Oil Company Deferred Compensation Plan or any similar plan maintained by the Employer shall receive excess Thrift accruals under that plan. No participant shall receive duplicate benefits under the Thrift Plan, Excess Benefit Plan, or a Deferred Compensation Plan.

2.3 Allocation of Liabilities under the Employee Matters Agreement

(a) Immediately following the Distribution Date this Excess Benefit Plan pursuant to the Employee Matters Agreement shall assume the Liabilities of the Marathon Petroleum Excess Benefit Plan and the Speedway Excess Benefit Plan representing any benefits accrued by individuals (1) who are either MRO Employees or Delayed Transfer Employees who move from the MPC Group to the MRO Group and (2) who have accrued benefits under either the Marathon Petroleum Excess Benefit Plan or the Speedway Excess Benefit Plan.

(b) Immediately following the Distribution Date this Excess Benefit Plan pursuant to the Employee Matters Agreement shall no longer have any Liabilities representing benefits accrued under this Excess Benefit Plan by individuals (1) who are MPC Employees or Speedway Employees or Delayed Transfer Employees who move from the MRO Group to the MPC Group and (2) who have accrued benefits under this Excess Benefit Plan, and the MPC Employees, Speedway Employees and Delayed Transfer Employees described in this Section 2.3(b) shall after the Distribution Date look exclusively to the Marathon Petroleum Excess Benefit Plan for the payment of such accrued benefits.

ARTICLE III. Excess Retirement and Thrift Benefits

3.1 Amount of Excess Retirement Benefit

The amount of a Participant' s benefit under this Section 3.1 (the "Excess Retirement Benefit") shall be determined as of the Participant' s Separation from Service, as follows:

(a) The amount of Excess Retirement Benefit which a Participant or Beneficiary (as defined in Section 3.3(b)) is entitled to receive shall be equal to the excess of (1) over (2) below:

(1) The amount of benefit which such Participant or Beneficiary would be entitled to receive under the Retirement Plan if such benefit were computed without giving effect to the Defined Benefit Limitations and including elected deferred compensation contributions as permitted under the Marathon Oil Company Deferred Compensation Plan or any similar plan maintained by the Employer; less

(2) The amount of benefit which such Participant or Beneficiary is entitled to receive under the Retirement Plan.

(b) The following individuals shall be entitled to an additional Excess Retirement Benefit equal to the difference between (1) and (2) below ("Special Excess Bonus Recognition"): (i) Marathon Oil Corporation ("MRO") and Marathon Oil Company employees ("MOC") who are MRO Officers in compensation Grade 19 and above; (ii) any Grade 19 and above employee of The Marathon Oil Corporation Controlled Group, excluding Speedway SuperAmerica or its subsidiaries, who is recommended by the Vice President of Human Resources of Marathon Oil Corporation and approved by the President of Marathon Oil Corporation; and (iii) Eligible Grandfather Employees.

(1) An amount calculated under the Retirement Plan benefit formula, without regard to any Code mandated limitations (including, but not limited to, the Defined Benefit Limits) and including elected deferred compensation contributions as permitted under the Marathon Oil Company Deferred Compensation Plan or any similar plan maintained by the Employer, and substituting the following Final Average Pay (FAP) definition for the definition of "Final Average Pay" contained in the Retirement Plan:

> Final Average Pay shall be the highest pay, excluding bonuses, of a member for any consecutive 36-month period during the last ten years of employment plus the highest three bonuses paid out of the last 10 years (not necessarily consecutive), divided by 36.

(2) An amount as normally determined under the Retirement Plan, plus any retirement benefit otherwise payable under the Excess Benefit Plan (*i.e.*, exclusive of any benefits attributable to the calculation in Section 3.1(b)(1) above).

For purposes of the calculations in (1) and (2) of this Section 3.1(b) "Eligible Grandfather Employee" means any current MRO and MOC employee eligible for Special Excess Bonus Recognition prior to August 27, 2003. However, an individual' s Eligible Grandfather Employee status shall permanently cease upon termination, retirement, or death as an employee.

(c) If a Participant is a Select Group Member or a Beneficiary (as defined in Section 3.3(b)) is the Beneficiary of a Select Group Member, he or she shall be entitled to an additional Excess Retirement Benefit equal to the excess of (1) over (2) below:

(1) The amount of the benefit which such Participant or Beneficiary would have been entitled to receive under the Retirement Plan as a Legacy Retirement Benefit if any changes in the Select Group Member' s Final Average Pay after December 31, 2009 had been taken into account under Section 4.02(c) of the Retirement Plan in computing his or her Legacy Retirement Benefit; less

(2) The amount of the benefit which such Participant or Beneficiary is entitled to receive under the Retirement Plan as a Legacy Retirement Benefit.

3.2 Amount of Excess Thrift Benefit

The amount of the benefit under this Section 3.2 (the "Excess Thrift Benefit") which a Participant or Beneficiary is entitled to receive shall be equal to the excess of (a) over (b) below for each calendar year accumulated with interest to date of payment at the "Cash with Interest" rate provided under Article VIII of the Thrift Plan:

(a) The amount of Company Contributions under Article VI of the Thrift Plan that would have been credited to the Participant' s Thrift Plan account if the Code Requirements were not given effect for such year and using the Participant' s rate of contributions at the time the limitation becomes effective as determined by the Plan Administrator; less

(b) The amount of Company Contributions actually credited to the Participant' s Thrift Plan account for such year.

3.3 Payment of Excess Benefit

A Participant shall be entitled to a cash distribution of the Participant' s Excess Retirement Benefit and Excess Thrift Benefit, as applicable (collectively, the "Excess Benefit"), as provided in this Section 3.3.

(a) Except as otherwise provided in this Section 3.3, a Participant' s Excess Benefit shall be paid in a lump sum within 90 days of Separation from Service for any reason other than death.

(b) In the event of the death of a Participant, the Participant' s Excess Benefit shall be paid to the Participant' s applicable Beneficiary in a lump sum within 90 days of the Participant' s death or, if earlier, within the 90-day period following the Participant' s Separation from Service as described in Section 3.3(a) (or, in the event of a Separation from Service of a Specified Employee (as defined below) not on account of death, the 90-day period described in Section 3.3(c)). The Participant' s "Beneficiary" shall be: (i) with respect to the Participant' s Excess Retirement Benefit, the Beneficiary will be his or her Eligible Surviving Spouse or estate (if no Eligible Surviving Spouse); and (ii) with respect to the Participant' s Excess Thrift Benefit, the Participant' s Beneficiary will be the beneficiary or beneficiaries designated under the Thrift Plan. In any event, if there is no valid Beneficiary under the terms of this Excess Benefit Plan, the Excess Benefit will be paid to the person or persons comprising the first surviving class of the eligible classes as set forth: (1) the Participant' s spouse; (2) the Participant' s natural born and legally adopted children; (3) the Participant' s surviving parents; (4) the Participant' s surviving brothers and sisters; and (5) the executor or administrator of the Participant' s estate.

(c) Distribution of the Excess Benefit of a Participant who the Plan Administrator determines is a Specified Employee (other than such Participant' s Grandfathered Accruals) shall be paid in a lump sum within the 90-day period following the first of the month following 6 months after Separation from Service (other than a Separation from Service on account of the death of Participant). In the event of a Separation from Service of a Specified Employee on account of death, payment shall be made pursuant to Section 3.3(b). Payment of a Specified Employee' s Grandfathered Accruals shall be made in accordance with Section 3.3(a).

(d) A Participant must be vested under the Retirement Plan in order for an Excess Retirement Benefit to be payable. The amount of any lump sum payment hereunder shall be determined by using the same factors and assumptions which would be used by the Retirement Plan for such Participant or Beneficiary at the Participant' s Separation from Service. The balance of any Excess Retirement Benefit not paid at the Participant' s Separation from Service shall accrue interest beginning at the Participant' s Separation from Service at a rate used under the Retirement Plan to determine the actuarial equivalent lump sum of a life only monthly annuity.

(e) A Participant must be fully vested under the Thrift Plan in order for an Excess Thrift Benefit to be payable. The balance of any Excess Thrift Benefit not paid at the Participant' s Separation from Service shall accrue interest at the "Cash with Interest" rate provided under Article VIII of the Thrift Plan until the entire balance has been paid. If the "Cash with Interest" rate becomes unavailable for any reason, whether for purposes of this Section 3.3(e) or for purposes of Section 3.2, the Company shall, at its sole discretion, substitute a similar interest rate which will be applicable for time periods thereafter.

(f) Distributions of 409A Accruals prior to January 1, 2009 were made under reasonable good faith interpretations of Code section 409A and transition guidance provided thereunder. Notwithstanding any contrary provisions of this Section 3.3, to the extent the Plan Administrator permitted a Participant to submit an election to receive payment in a form of distribution other than a lump sum and such payment commenced prior to 2009, the distribution of such Participant' s Excess Benefit after 2008 shall be governed by procedures established by the Plan Administrator.

ARTICLE IV. Funding

Benefits under this Excess Benefit Plan shall be paid from the general assets of the applicable Employer. This Excess Benefit Plan shall be administered as an unfunded plan which is maintained primarily for the purpose of providing supplemental retirement compensation "for a select group of management or highly compensated employees" as set forth in sections 201(2), 301(3), and 401(a)(1) of ERISA, and is not intended to meet the qualification requirements of section 401 of the Code. Any assets set aside by the Employer for the purpose of paying benefits under this Excess Benefit Plan shall not be deemed to be the property of the Participant and shall be subject to claims of creditors of the Employer. No Participant or other person shall have any claim against, right to, or security or other interest in, any fund, account or asset of the Employer from which any payment under the Excess Benefit Plan may be made. Any use of the words "contributions" or "contribute," or any similar phrase, shall not require actual contributions or funding of this Excess Benefit Plan and is only used for convenience when describing the deferral activities of this Excess Benefit Plan.

ARTICLE V. Plan Administration

5.1 General Duty

The Company has delegated its administrative authority hereunder to the Plan Administrator of the Retirement Plan or its successor (the "Plan Administrator.") It shall be the principal duty of the Plan Administrator to determine that the provisions of this Excess Benefit Plan are carried out in accordance with its terms, for the exclusive benefit of persons entitled to participate in the Excess Benefit Plan.

5.2 Plan Administrator' s General Powers, Rights and Duties

The Plan Administrator shall have full power to administer this Excess Benefit Plan in all of its details, subject to the applicable requirements of law. For this purpose, the Plan Administrator is, as respects the rights and obligations of all parties with an interest in this Excess Benefit Plan, given the powers, rights and duties specifically stated elsewhere in this Excess Benefit Plan, or any other document, and in addition is given, but not limited to, the following powers, rights and duties:

(a) to determine all questions arising under this Excess Benefit Plan, including the power to determine the rights or eligibility of Employees or Participants and any other persons, and the amounts of their contributions or benefits under the Excess Benefit Plan, to interpret this Excess Benefit Plan, and to remedy ambiguities, inconsistencies or omissions;

(b) to adopt such rules of procedure and regulations, including the establishment of any claims procedure that may be required by law, as in its opinion may be necessary for the proper and efficient administration of this Excess Benefit Plan and as are consistent with this Excess Benefit Plan;

(c) to direct payments or distributions from thise Excess Benefit Plan in accordance with the provisions of this Excess Benefit Plan;

(d) to develop such information as may be required by it for tax or other purposes as respects this Excess Benefit Plan; and

(e) to employ agents, attorneys, accountants or other persons (who also may be employed by the Company), and allocate or delegate to them such powers as the Plan Administrator may consider necessary or advisable to properly carry out the administration of this Excess Benefit Plan.

The Plan Administrator’ s decision in any matter involving the interpretation and application of this Excess Benefit Plan shall be final and binding. In the event the Plan Administrator would have to decide any issue under this Excess Benefit Plan which could affect the form or timing of the payment of deferred compensation under this Excess Benefit Plan, then the Company shall make that decision.

5.3 Indemnification of Administrator

The Company agrees to indemnify and to defend to the fullest extent permitted by law any Employee serving as the Plan Administrator against all liabilities, damages, costs and expenses (including attorney’ s fees and amounts paid in settlement of any claims approved by the Company) occasioned by any act of omission to act in connection with this Excess Benefit Plan, if such act of omission is or was in good faith. This Section 5.3 shall comply with Code section 409A and Treasury Regulation section 1.409A-3(i)(1)(iv) with regard to the requirements for reimbursements, to the extent applicable, for the period that such Employee’ s indemnification right hereunder shall exist.

5.4 Information Required by Plan Administrator

The Plan Administrator shall obtain such data and information as deemed necessary or desirable in order to administer this Excess Benefit Plan. The records of the Company as to an Employee’ s or Participant’ s period or periods of employment, termination of employment and the reason therefor, leave of absence, re-employment and earnings will be conclusive on all persons unless determined by independent agents or delegates of the Plan Administrator to be incorrect. Participants and other persons entitled to benefits under this Excess Benefit Plan also shall furnish the Plan Administrator with such evidence, data or information, as the Plan Administrator considers necessary or desirable to administer this Excess Benefit Plan.

5.5 Claims and Review Procedures

(a) Claims Procedure**.** If a Participant believes any rights or benefits are being improperly denied under this Excess Benefit Plan, such Participant may file a claim in writing with the Plan Administrator. If any such claim is wholly or partially denied, the Plan Administrator shall notify such Participant of its decision in writing. Such notification shall be written in a manner calculated to be understood by such Participant and shall contain (i) specific reasons for the denial, (ii) specific reference to pertinent Excess Benefit Plan provisions, (iii) a description of any additional material or information necessary for the Participant to perfect such claim and an explanation of why such material or information is necessary, and (iv) information as to the steps to be taken if the Participant wishes to submit a request for review. Such notification shall be given within 90 days after the claim is received by the Plan Administrator (or within 180 days, if special circumstances require an extension of time for processing the claim, and if written notice of such extension and circumstances is given to such Participant within the initial 90 day period.) If such notification is not given within such period the claim shall be considered denied as of the last day of such period and such Participant may request a review of his claim.

(b) Review Procedure**.** Within 60 days after the date on which a Participant receives a written notice of a denied claim (or, if applicable, within 60 days after the date on which such denial is considered to have occurred) such Participant (or the Participant' s duly authorized representative) may (i) file a written request with the Plan Administrator for a review of his denied claim and of pertinent documents, and (ii) submit written issues and comments to the Plan Administrator. The Plan Administrator shall notify such Participant of its decision in writing. Such notification shall be written in a manner calculated to be understood by such Participant and shall contain specific reasons for the decision as well as specific references to pertinent Excess Benefit Plan provision. The decision on review shall be made within 60 days after the request for review is received by the Plan Administrator (or within 120 days, if special circumstances require an extension of time for processing the request, such as an election by the Plan Administrator to hold a hearing, and if written notice of such extension and circumstances is given to such person within the initial 60 day period). If the decision on review is not made within such period, the claim shall be considered denied.

(c) Section 409A Requirements. Any claim for benefits under this Section must be made by the Participant no later than the time prescribed by Code section 409A. If a claimant' s claim or appeal is approved, any resulting payment of benefits will be made no later than the time prescribed for payment of benefits by Code Section 409A.

ARTICLE VI. Modification and Discontinuance

6.1 Amendment and Termination

The Company reserves the right to modify, suspend, or terminate this Excess Benefit Plan at any time, in whole or in part, in such manner as it shall determine, provided that such action conforms to the requirements of Code section 409A. Included in the Company' s right to amend, suspend or terminate is the Company' s right at any time to no longer permit any additional Participants under this Excess Benefit Plan, to cease benefit accruals, and to distribute all benefits upon Excess Benefit Plan termination, all subject to the requirements of Code section 409A. The Plan Administrator may promulgate rules and procedures from time to time to carry out the provisions of this Article VI. However, in no event shall the Company have the right to eliminate or reduce any benefit, which has been vested or become forfeitable under this Excess Benefit Plan. No future amendment to this Excess Benefit Plan shall apply to Grandfathered Accruals to the extent such provision or amendment would constitute a "material modification" within the meaning of Code section 409A with respect to the Grandfathered Accruals unless such amendment expressly indicates otherwise.

6.2 Delegation of Authority

In addition to the other methods of amending MOC' s employee benefit plans, practices, and policies (hereinafter referred to as "MOC Employee Benefit Plans") which have been authorized, or may in the future be authorized, by the Marathon Oil Company Board of Directors, the Company' s Vice President of Human Resources may approve the following types of amendments to MOC Employee Benefit Plans:

(a) With the opinion of counsel, technical amendments required by applicable laws and regulations;

(b) With the opinion of counsel, amendments that are clarifications of plan provisions;

(c) Amendments in connection with a signed definitive agreement governing a merger, acquisition or divestiture such that, for MOC Employee Benefit Plans, needed changes are specifically described in the definitive agreement, or if not specifically described in the definitive agreement, the needed changes are in keeping with the intent of the definitive agreement;

(d) Amendments in connection with changes that have a minimal cost impact (as defined below) to the Company; and

(e) With the opinion of counsel, amendments in connection with changes resulting from state or federal legislative actions that have a minimal cost impact (as defined below) to the Company.

For purposes of the above, "minimal cost impact" is defined as an annual cost impact to the Company per MOC Employee Benefit Plan case that does not exceed the greater of (i) an amount that is less than one-half of one percent of its documented total cost (including administrative costs) for the previous calendar year, or (ii) $500,000.

6.3 Transfer of Liabilities

In the event of a corporate transaction involving a Participant' s Employer, the liabilities with respect to the Participant' s Excess Benefit may be transferred to the entity or organization that becomes the Participant' s employer following the corporate transaction to the extent that such transfer (i) is permitted by applicable law, (ii) with respect to the 409A Accruals is consistent with Code section 409A, and (iii) with respect to Grandfathered Accruals, does not represent a material enhancement of the Participant' s benefits or rights available under the Excess Benefit Plan on October 3, 2004. For these purposes, a corporate transaction shall include, but not be limited to, a merger, consolidation, separation, reorganization, liquidation, split-up, or spin-off.

ARTICLE VII. General Provisions

7.1 Notices

Each Participant entitled to benefits under this Excess Benefit Plan must file in writing with the Plan Administrator such Participant' s post office address and each change of post office address. Any communication, statement or notice addressed to any such Participant at the last post office address filed with the Plan Administrator will be binding upon such person for all purposes of this Excess Benefit Plan, and the Plan Administrator shall not be obligated to search for or ascertain the whereabouts of any Participant. Any notice or document required to be given or filed with the Plan Administrator shall be considered as given or filed if delivered or mailed by registered mail, postage prepaid, to Robert L. Sovine, Jr., Vice President of Human Resources, P.O. Box 3128, Houston, TX 77253.

7.2 Employment Rights

This Excess Benefit Plan does not constitute a contract of employment, and participation in this Excess Benefit Plan will not give any Participant the right to be retained in the employ of the Company or any Employer nor any right or claim to any benefit under this Excess Benefit Plan, unless such right or claim has specifically accrued under the terms of this Excess Benefit Plan.

7.3 Interests Not Transferable

Except as may be required by law, including the federal income and employment tax withholding provisions of the Code, or of an applicable state' s income tax act, the interests of Participants and their Beneficiaries under this Excess Benefit Plan are not subject to the claims of their creditors and may not be voluntarily or involuntarily sold, transferred, alienated, assigned or encumbered. Notwithstanding any provision of this Excess Benefit Plan to the contrary, this Excess Benefit Plan shall not recognize or give effect to any domestic relations order attempting to alienate, transfer or assign any Participant benefits. The preceding shall not preclude the Employer from asserting any claim for damages or for any debt that the Employer may have with respect to the Participant; provided that any offset shall apply only where such debt is incurred in the ordinary course of the service relationship between the Employer and the Participant, the entire amount of reduction in any of the Participant' s taxable years does not exceed $5,000, and the reduction is made at the same time and in the same amount as the debt otherwise would have been due and collected from the Participant.

7.4 Facility of Payment

When a Participant entitled to benefits under this Excess Benefit Plan is under a legal disability, or, in the Plan Administrator' s opinion, is in any way incapacitated so as to be unable to manage their financial affairs, the Plan Administrator may direct that the benefits to which such Participant otherwise would be entitled shall be made to such Participant' s legal representative, or to such other person or persons as the Plan Administrator may direct the application of the benefits for the benefit of such Participant. Any payment made in accordance with such provisions of this Section 7.4 shall be a full and complete discharge of any liability for such payment.

7.5 Controlling State Law

To the extent not superseded by the laws of the United States, the laws of the State of Texas shall be controlling in all matters relating to this Excess Benefit Plan.

7.6 Severability

In case any provisions of this Excess Benefit Plan shall be held illegal or invalid for any reason, such illegality or invalidity shall not affect the remaining provisions of this Excess Benefit Plan, and this Excess Benefit Plan shall be construed and enforced as if such illegal and invalid provisions had never been set forth in this Excess Benefit Plan.

7.7 Statutory References

All references to the Code and ERISA include reference to any comparable or succeeding provisions of any legislation, which amends, supplements or replaces such section or subsection.

7.8 Headings

Section headings and titles are for reference only. In the event of a conflict between a title and the content of a section, the content of the section shall control.

7.9 Non-taxable Benefits

It is the intention of the Company that this Excess Benefit Plan meet all requirements of the Code so that the benefits provided be non-taxable during the period of deferral and until actual distribution is made.

7.10 Affect on Other Benefit Plans

Any benefit payable under the Retirement Plan or the Thrift Plan shall be paid solely in accordance with the terms and provisions of those Plans, and nothing in this Excess Benefit Plan shall operate or be construed in any way to modify, amend, or affect the terms and provisions of the Retirement Plan or Thrift Plan.

IN WITNESS WHEREOF, Marathon Oil Company has caused its name to be hereunto subscribed by its Vice President, Marathon Oil Company.

MARATHON OIL COMPANY

By: /s/ Robert L. Sovine

Its: Vice President, Human Resources

Exhibit 10.32

MARATHON OIL COMPANY

DEFERRED COMPENSATION PLAN

Amended & Restated Effective

June 30, 2011

MARATHON OIL COMPANY

DEFERRED COMPENSATION PLAN

This document contains the provisions of the Marathon Oil Company Deferred Compensation Plan (the "Plan") as of June 30, 2011, and shall apply only to Accounts that are not fully distributed as of such date, including 409A Deferrals and Grandfathered Deferrals that are exempt from Code section 409A.

With respect to the 409A Deferrals, the Plan, as amended and restated, is intended to conform to the requirements of Code section 409A and the regulations thereunder, and, in all respects, shall be administered and construed in accordance with such requirements. With respect to the Grandfathered Deferrals, the Plan, as amended and restated, does not represent a material enhancement of the benefits or rights available under the Plan on October 3, 2004.

ARTICLE I. Definitions

1.1. "**409A Deferrals**" means those amounts deferred or that became vested after 2004, with earnings and losses attributable thereto, as determined in accordance with Code section 409A.

1.2. "**Account**" means an unfunded liability of the Employer in the name of each Participant. "Account" shall refer to the Participant's entire benefit accrued under the terms of the Plan unless a provision refers specifically to any "Sub-Account" as described in Article VII.

1.3. "**Affiliated Company**" means the Company and each related company or business which is part of the same controlled group under Code sections 414(b) or 414(c); provided that where specified by the Employer in accordance with Code section 409A in applying Code section 1563(a)(1) - (a)(3) for purposes of determining a controlled group of corporations under Code section 414(b) and in applying Treasury Regulation section 1.414(c)-2 for purposes of determining whether trades or businesses are under common control under Code section 414(c), the phrase "at least 50 percent" is used instead of "at least 80 percent." The term "Affiliated Company" shall also include any entity that previously met the requirements of an Affiliated Company as set forth herein that continues to employ a Participant to the extent so designated by the Plan Administrator.

1.4. "**Beneficiary**" means any person(s) designated in writing by a Participant to receive payment under this Plan in the event of the Participant's death. In the event the Participant is married and has designated no other beneficiary (or if the designated beneficiary has predeceased the Participant), Beneficiary shall mean the Participant's spouse. In the event the Participant is not married at death and has designated no beneficiary (or if the designated beneficiary has predeceased the Participant), Beneficiary shall mean the Participant's estate.

1.5. "**Board**" means the Board of Directors of Marathon Oil Corporation.

1.6. "**Code**" means the Internal Revenue Code of 1986, as amended including regulations and other guidance of general applicability promulgated thereunder.

1.7. "**Code section 409A**" means, collectively, section 409A of the Code and any Treasury and Internal Revenue Service regulations and guidance issued thereunder.

1.8. "**Company**" means Marathon Oil Company.

1.9. "**Compensation**" means gross pay as defined in the Thrift Plan without regard to any Code limitations.

1.10. "**Eligible Employee**" means a Marathon Oil Corporation Officer in Grade 88 and above and, if recommended by the Vice President of Human Resources of Marathon Oil Corporation and approved by the President of Marathon Oil Corporation, any Grade 88 and above Employee of an Affiliated Company, excluding Speedway SuperAmerica or its subsidiaries.

1.11. “**Eligible Former Speedway Employee**” means an individual who (a) was employed by Speedway LLC or its subsidiaries prior to the spin-off of Marathon Petroleum Corporation from Marathon Oil Corporation, (b) who had an account balance under the Speedway Deferred Compensation Plan and (c) who is employed by Company or an Affiliated Company at the effective time of the spin-off of Marathon Petroleum Corporation from Marathon Oil Corporation.

1.12. “**Eligible Grandfather Employee**” means a Marathon Oil Corporation employee or a Marathon Oil Company employee who, prior to August 27, 2003, was in compensation Grade 19 and above or a Vice President; provided, however, that an individual’ s Eligible Grandfather Employee status shall permanently cease upon termination, retirement, or death as an active employee.

1.13. “**Employee**” means any individual employed by the Company or an Affiliated Company.

1.14. “**Employer**” means Marathon Oil Corporation, the Company, Marathon Service Company and any other Affiliated Company that adopts the Plan with the Board’ s consent.

1.15. “**ERISA**” means the Employee Retirement Income Security Act of 1974 as amended.

1.16. “**Grandfathered Deferrals**” means those amounts deferred and vested before January 1, 2005, with earnings and losses attributable thereto, as determined in accordance with Code section 409A.

1.17. “**Grandfathered Deferrals Sub-Account**” means that portion of a Participant’ s Account that consists of the Grandfathered Deferrals.

1.18. “**Participant**” means an Eligible Employee, Eligible Former Speedway Employee or Eligible Grandfathered Employee who either (a) elects to participate in and/or receives contributions under the Plan pursuant to Article III or Article IV of this Plan or (b) has an Account under this Plan as a result of the transfer of liabilities from the Marathon Petroleum Deferred Compensation Plan or the Speedway Deferred Compensation Plan.

1.19. “**Plan**” means The Marathon Oil Company Deferred Compensation Plan as set forth in this document.

1.20. “**Plan Administrator**” means Robert L. Sovine, Jr. and any successor as designated by the Company to administer the Plan.

1.21. “**Plan Year**” means the 12-consecutive month period beginning each January 1 and ending each December 31.

1.22. “**Salary Deferral**” means the total amount deferred by the Participant from Compensation under Article III.

1.23. “**Separation from Service**” shall have the same meaning as set forth under Code section 409A with respect to an Affiliated Company.

1.24. “**Specified Employee**” shall have the meaning as set forth under Code section 409A and as determined by the Employer in accordance with its established policy.

1.25. “**Thrift Plan**” shall mean the Marathon Oil Company Thrift Plan.

ARTICLE II. Eligibility

2.1. **Eligibility**

A newly hired Eligible Employee is eligible to participate in the Plan as of the date and in accordance with the rules established for such purpose by the Plan Administrator, consistent with Code section 409A. Any other Eligible Employee is eligible to participate in the Plan on the January 1 coinciding with or next following the date he or she becomes an Eligible Employee. Any individual who was an Eligible Employee or an Eligible Grandfather Employee as of December 31, 2008 shall remain eligible to participate as of January 1, 2009. Any Participant who is an Eligible Former Speedway Employee shall not be permitted to make Salary Deferrals or have any amounts credited to his or her Account pursuant to Article IV unless such individual is an Eligible Employee.

2.2. **Termination of Participation**

In the event that a Participant ceases to be an Eligible Employee (or an Eligible Grandfather Employee), the Participant' s current Salary Deferral election shall remain in effect, and thereafter, the Participant shall make no further deferrals unless and until the Participant again becomes eligible under Section 2.1.

ARTICLE III. Deferral of Compensation

3.1. **Annual Elections**

Each Participant may elect, prior to the first day of any Plan Year, to make Salary Deferrals (in 1% increments) of up to 20% of his or her Compensation for the Plan Year as provided in the deferral election form. A newly hired Eligible Employee who becomes a Participant in the year of hire may elect to make Salary Deferrals of his or her Compensation for such year pursuant to rules established for such purpose by the Plan Administrator, consistent with Code section 409A.

3.2. **Manner of Deferral**

A Participant' s Salary Deferrals may be taken from the Participant' s Compensation ratably during the applicable Plan Year or in any other manner determined by the Plan Administrator; provided that such Salary Deferrals during the Plan Year, in the aggregate, reflect the Participant' s Salary Deferral election in accordance with Code section 409A.

3.3. **General Election Rules**

The Plan Administrator may establish, in its discretion, from time to time, rules allowing deferral elections to be made later than prescribed in this Article III to the extent permitted under Code section 409A. Deferral elections shall be in the form and manner required by the Plan Administrator, shall be irrevocable and shall not defer more than that amount which is otherwise available for payment to the Participant net of any and all required federal, state and local withholding obligations (determined taking into account the effect of the deferral) and other qualified plan and pre-tax salary deferrals. Notwithstanding any other provision of this Article III, the Plan Administrator may require that a Participant submit deferral elections prior to the date otherwise specified in this Article III.

ARTICLE IV. Other Contributions

4.1. **Thrift Plan Make-up Matching Contributions**

(a) During each year that a Participant is eligible to participate under Article II, such Participant shall be credited with an amount equal to any match that would have been made under the Thrift Plan, the Marathon Oil Company Excess Benefit Plan, or any other similar plan maintained by an Affiliated Company but that is not made solely because of limitations under the Code or any compensation limit imposed on deferrals in the Thrift Plan.

(b) The match credited under this Section 4.1 shall be determined at the rate of the maximum potential match under the Thrift Plan.

4.2. **Matching Contributions for New Hires in Waiting Period**

New hires who are eligible for this Plan under Section 2.1 and who, except for the provisions governing the Thrift Plan' s "waiting period," would otherwise be eligible to participate in the Thrift Plan, shall be credited with a Company match equal to the maximum potential Company match under the Thrift Plan multiplied by the Participant' s gross pay (as defined in the Thrift Plan but disregarding any limitations on eligible compensation as may be imposed by the Code) during the Thrift Plan' s waiting period. This accrual shall cease to the extent that, upon the first date of participation eligibility in the Thrift Plan, the employee is eligible under the Plan for the Thrift Plan Company matching contributions.

4.3. **Matching Contributions on Salary Deferrals**

A Participant shall be credited each year with a match equal to such Participant' s Salary Deferrals during the year multiplied by the rate of the maximum potential match under the Thrift Plan.

4.4. **Manner of Deferral**

Matching contributions under this Article IV may be credited on a pay-period basis or in any other manner determined by the Plan Administrator; provided that such matching contributions during the Plan Year, in the aggregate, reflect the correct amount determined under this Article IV.

ARTICLE V. Accounting

5.1. **Allocation to Participant' s Account**

Any Salary Deferrals under Article III or matching contributions under Article IV shall be credited to the Participant' s Account in the manner designated by the Plan Administrator. In addition, account balances transferred from the Speedway Deferred Compensation Plan or the Marathon Petroleum Deferred Compensation Plan shall be credited to the Participant' s Account in the manner designated by the Plan Administrator.

5.2. **Earnings**

A Participant may select from a list of hypothetical investment options that will be the same as the investment options offered and modified from time to time under the terms of the Thrift Plan (other than the stock of Marathon Oil Corporation). Earnings, gains and losses received on the investments will be credited to the Participant' s Account in the manner designated by the Plan Administrator. The Plan Administrator shall develop such accounting procedures as it, in its sole discretion, deems advisable to properly reflect the value attributable to the Participant' s Account.

ARTICLE VI. Vesting

A Participant' s Salary Deferrals shall always be immediately vested. Matching contributions provided under Article IV shall vest as provided under the terms and conditions of the Thrift Plan. Any portion of a Participant' s Account which is attributable to a transfer of liabilities from the Marathon Petroleum Deferred Compensation Plan or the Speedway Deferred Compensation Plan in connection with the spin-off of Marathon Petroleum Corporation from Marathon Oil Corporation shall be fully vested as of the effective time of the spin-off.

ARTICLE VII. Distribution of Benefits

A Participant shall be entitled to a cash distribution of the Participant' s Account as provided in this Article VII.

7.1. **General Rule for Distributions**

Except as otherwise provided in this Article VII, a Participant' s Account shall be paid in a lump sum within 90 days of Separation from Service for any reason other than death.

7.2. **Death**

In the event of the death of a Participant, the Participant' s Account shall be paid to the Participant' s Beneficiary in a lump sum within 90 days of the Participant' s death or, if earlier, within the 90-day period following the Participant' s Separation from Service as described in Section 7.1 (or, in the event of a Separation from Service of a Specified Employee not on account of death, the 90-day period described in Section 7.4).

7.3. **Earnings on Unpaid Balances**

The Participant' s Account shall be credited with earnings and losses pursuant to the provisions set forth in Article V until fully paid.

7.4. **Delay for Specified Employees**

Distribution of the Account of a Participant who the Plan Administrator determines is a Specified Employee (other than such Participant' s Grandfathered Deferrals Sub-Account) shall be paid in a lump sum within the 90-day period following the first of the month following 6 months after Separation from Service (other than a Separation from Service on account of the death of

Participant). In the event of a Separation from Service of a Specified Employee on account of death, payment shall be made pursuant to Section 7.2. Payment of a Specified Employee' s Grandfathered Deferrals Sub-Account shall be made in accordance with Sections 7.1.

7.5. **Eligible Former Speedway Employees**

If a Participant who is an Eligible Former Speedway Employee, then the distribution of the portion of his or her Account which was transferred from the Speedway Deferred Compensation Plan shall continue to be governed by the terms of the Speedway Deferred Compensation Plan as in effect on the date as of which liabilities are transferred from the Speedway Deferred Compensation Plan. The Speedway Deferred Compensation Plan as in effect during June 2011 (the month during which liabilities will be transferred from such plan) is attached as Appendix 1 to this Plan.

7.6. **Employees of the Marathon Petroleum Corporation Controlled Group**

On or about June 17, 2011 and prior to the effective time of the spin-off of Marathon Petroleum Corporation from Marathon Oil Corporation, liabilities under this Plan were transferred to the Marathon Petroleum Deferred Compensation Plan for each employee who (a) had an Account under this Plan and (b) was expected to be employed by Marathon Petroleum Corporation or its subsidiaries immediately following the spin-off of Marathon Petroleum Corporation. Such employees ceased to be Participants in this Plan effective as of the effective time of the transfer of liabilities to the Marathon Petroleum Deferred Compensation Plan.

ARTICLE VIII. Funding

Benefits under this Plan shall be paid from general assets of the Employer. This Plan shall be administered as an unfunded plan which is maintained primarily for the purpose of providing supplemental retirement compensation "for a select group of management or highly compensated employees" as set forth in sections 201(2), 301(3), and 401(a)(1) of the ERISA, and is not intended to meet the qualification requirements of section 401 of the Code. Any assets set aside by the Employer for the purpose of paying benefits under this Plan shall not be deemed to be the property of the Participant and shall be subject to claims of creditors of the Employer. No Participant or other person shall have any claim against, right to, or security or other interest in, any fund, account or asset of the Employer from which any payment under the Plan may be made. Any use of the words "contributions" or "contribute," or any similar phrase, shall not require actual contributions or funding of this Plan and is only used for convenience when describing the deferral activities of this Plan.

ARTICLE IX. Plan Administration

9.1. **General Duty**

The Plan shall be administered by the Plan Administrator who shall be appointed by the Company and shall serve in such capacity until resignation or removal by the Company. It shall be the principal duty of the Plan Administrator to determine that the provisions of the Plan are carried out in accordance with its terms, for the exclusive benefit of persons entitled to participate in the Plan.

9.2. **Plan Administrator's General Powers, Rights and Duties**

The Plan Administrator shall have full power to administer the Plan in all of its details, subject to the applicable requirements of law. For this purpose, the Plan Administrator is, as respects the rights and obligations of all parties with an interest in this Plan, given the powers, rights and duties specifically stated elsewhere in the Plan, or any other document, and in addition is given, but not limited to, the following powers, rights and duties:

(a) to determine all questions arising under the Plan, including the power to determine the rights or eligibility of Employees or Participants and any other persons, and the amounts of their contributions or benefits under the Plan, to interpret the Plan, and to remedy ambiguities, inconsistencies or omissions;

(b) to adopt such rules of procedure and regulations, including the establishment of any claims procedure that may be required by law, as in its opinion may be necessary for the proper and efficient administration of the Plan and as are consistent with the Plan;

(c) to direct payments or distributions from the Plan in accordance with the provisions of the Plan;

(d) to develop such information as may be required by it for tax or other purposes as respects the Plan; and

(e) to employ agents, attorneys, accountants or other persons (who also may be employed by the Company), and allocate or delegate to them such powers as the Plan Administrator may consider necessary or advisable to properly carry out the administration of the Plan.

The Plan Administrator' s decision in any matter involving the interpretation and application of this Plan shall be final and binding. In the event the Plan Administrator would have to decide any issue under the Plan which could affect the form or timing of the payment of deferred compensation under the Plan, then the Company shall make that decision.

9.3. **Indemnification of Administrator**

The Company agrees to indemnify and to defend to the fullest extent permitted by law any Employee serving as the Plan Administrator against all liabilities, damages, costs and expenses (including attorney' s fees and amounts paid in settlement of any claims approved by the Company) occasioned by any act of omission to act in connection with the Plan, if such act of omission is or was in good faith. This Section 9.3 shall comply with Code section 409A and Treasury Regulation section 1.409A-3(i)(1)(iv) with regard to the requirements for reimbursements, to the extent applicable, for the period that such Employee' s indemnification right hereunder shall exist.

9.4. **Information Required by Plan Administrator**

The Plan Administrator shall obtain such data and information as deemed necessary or desirable in order to administer the Plan. The records of the Company as to an Employee' s or Participant' s period or periods of employment, termination of employment and the reason therefor, leave of absence, re-employment and earnings will be conclusive on all persons unless determined by independent agents or delegates of the Plan Administrator to be incorrect. Participants and other persons entitled to benefits under the Plan also shall furnish the Plan Administrator with such evidence, data or information, as the Plan Administrator considers necessary or desirable to administer the Plan.

9.5. **Claims and Review Procedures**

(a) **Claims Procedure.** If a Participant believes any rights or benefits are being improperly denied under the Plan, such Participant may file a claim in writing with the Plan Administrator. If any such claim is wholly or partially denied, the Plan Administrator shall notify such Participant of its decision in writing. Such notification shall be written in a manner calculated to be understood by such Participant and shall contain (i) specific reasons for the denial, (ii) specific reference to pertinent Plan provisions, (iii) a description of any additional material or information necessary for the Participant to perfect such claim and an explanation of why such material or information is necessary, and (iv) information as to the steps to be taken if the Participant wishes to submit a request for review. Such notification shall be given within 90 days after the claim is received by the Plan Administrator (or within 180 days, if special circumstances require an extension of time for processing the claim, and if written notice of such extension and circumstances is given to such Participant within the initial 90 day period.) If such notification is not given within such period the claim shall be considered denied as of the last day of such period and such Participant may request a review of his claim.

(b) **Review Procedure.** Within 60 days after the date on which a Participant receives a written notice of a denied claim (or, if applicable, within 60 days after the date on which such denial is considered to have occurred) such Participant (or the Participant' s duly authorized representative) may (i) file a written request with the Plan Administrator for a review of his denied claim and of pertinent documents, and (ii) submit written issues and comments to the Plan Administrator. The Plan Administrator shall notify such Participant of its decision in writing. Such notification shall be written in a manner calculated to be understood by such Participant and shall contain specific reasons for the decision as well as specific references to pertinent Plan provision. The decision on review shall be made within 60 days after the request for review is received by the Plan Administrator (or within 120 days, if special circumstances require an extension of time for processing the request, such as an election by the Plan Administrator to hold a hearing, and if written notice of such extension and circumstances is given to such person within the initial 60 day period). If the decision on review is not made within such period, the claim shall be considered denied.

(c) **Section 409A Requirements**. Any claim for benefits under this Section must be made by the Participant no later than the time prescribed by Code section 409A. If a claimant' s claim or appeal is approved, any resulting payment of benefits will be made no later than the time prescribed for payment of benefits by Code Section 409A.

ARTICLE X. Modification and Discontinuance

10.1. **Amendment and Termination**

The Company reserves the right to modify, suspend, or terminate the Plan at any time, in whole or in part, in such manner as it shall determine, provided that such action conforms to the requirements of Code section 409A. Included in the Company' s right to amend, suspend or terminate is the Company' s right at any time to no longer permit any additional Participants under the Plan, to cease making Company allocations, and to distribute all Account balances upon Plan termination, all subject to the requirements of Code section 409A. The Plan Administrator may promulgate rules and procedures from time to time to carry out the provisions of this Article X. However, in no event shall the Company have the right to eliminate or reduce any benefit, which has been vested or become forfeitable under the Plan, pursuant to Article VI. No future amendment to the Plan shall apply to Grandfathered Deferrals to the extent such provision or amendment would constitute a "material modification" within the meaning of Code section 409A with respect to the Grandfathered Deferrals unless such amendment expressly indicates otherwise.

10.2. **Delegation of Authority**

In addition to the other methods of amending the Company' s employee benefit plans, practices, and policies (hereinafter referred to as "MOC Employee Benefit Plans") which have been authorized, or may in the future be authorized, by the Board, the Company' s Vice President of Human Resources may approve the following types of amendments to MOC Employee Benefit Plans:

(a) With the opinion of counsel, technical amendments required by applicable laws and regulations;

(b) With the opinion of counsel, amendments that are clarifications of plan provisions;

(c) Amendments in connection with a signed definitive agreement governing a merger, acquisition or divestiture such that, for MOC Employee Benefit Plans, needed changes are specifically described in the definitive agreement, or if not specifically described in the definitive agreement, the needed changes are in keeping with the intent of the definitive agreement;

(d) Amendments in connection with changes that have a minimal cost impact (as defined below) to the Company; and

(e) With the opinion of counsel, amendments in connection with changes resulting from state or federal legislative actions that have a minimal cost impact (as defined below) to the Company.

For purposes of the above, "minimal cost impact" is defined as an annual cost impact to the Company per MOC Employee Benefit Plan case that does not exceed the greater of (i) an amount that is less than one-half of one percent of its documented total cost (including administrative costs) for the previous calendar year, or (ii) $500,000.

10.3. **Transfer of Liabilities**

(a) **General.** In the event of a corporate transaction involving a Participant' s Employer, the liabilities with respect to the Participant' s Account may be transferred to the entity or organization that becomes the Participant' s employer following the corporate transaction to the extent that such transfer (i) is permitted by applicable law, (ii) with respect to the 409A Deferrals is consistent with Code section 409A, and (iii) with respect to Grandfathered Deferrals, does not represent a material enhancement of the Participant' s benefits or rights available under the Plan on October 3, 2004. For these purposes, a corporate transaction shall include, but not be limited to, a merger, consolidation, separation, reorganization, liquidation, split-up, or spin-off.

(b) **Spin-Off of Marathon Petroleum Corporation.** Liabilities have been accepted from the Marathon Petroleum Deferred Compensation Plan or the Speedway Deferred Compensation Plan for each employee who (a) had an account balance under the Marathon Petroleum Deferred Compensation Plan or Speedway Deferred Compensation Plan and (b) who is expected to be employed by the Company or an Affiliated

Company at the effective time of the spin-off of Marathon Petroleum Corporation from Marathon Oil Company. Liabilities have been transferred to the Marathon Petroleum Deferred Compensation Plan for each individual who (a) had an Account balance under this Plan and (b) is expected to be employed by Marathon Petroleum Corporation or an affiliate of Marathon Petroleum Corporation at the effective time of the spin-off of Marathon Petroleum Corporation from Marathon Oil Company. Individuals with respect to whom liabilities were transferred from this Plan to the Marathon Petroleum Deferred Compensation Plan are no longer Participants in this Plan.

ARTICLE XI. General Provisions

11.1. **Notices**

Each Participant entitled to benefits under the Plan must file in writing with the Plan Administrator such Participant' s post office address and each change of post office address. Any communication, statement or notice addressed to any such Participant at the last post office address filed with the Plan Administrator will be binding upon such person for all purposes of the Plan, and the Plan Administrator shall not be obligated to search for or ascertain the whereabouts of any Participant. Any notice or document required to be given or filed with the Plan Administrator shall be considered as given or filed if delivered or mailed by registered mail, postage prepaid, to Robert L. Sovine, Jr., Vice President of Human Resources, P.O. Box 3128, Houston, Texas 77253.

11.2. **Employment Rights**

The Plan does not constitute a contract of employment, and participation in the Plan will not give any Participant the right to be retained in the employ of the Employer or an Affiliated Company nor any right or claim to any benefit under the Plan, unless such right or claim has specifically accrued under the terms of the Plan.

11.3. **Interests Not Transferable**

Except as may be required by law, including the federal income and employment tax withholding provisions of the Code, or of an applicable state' s income tax act, the interests of Participants and their beneficiaries under this Plan are not subject to the claims of their creditors and may not be voluntarily or involuntarily sold, transferred, alienated, assigned or encumbered. Notwithstanding any provision of the Plan to the contrary, the Plan shall not recognize or give effect to any domestic relations order attempting to alienate, transfer or assign any Participant benefits. The preceding shall not preclude the Employer from asserting any claim for damages or for any debt that the Employer may have with respect to the Participant; provided that any offset shall apply only where such debt is incurred in the ordinary course of the service relationship between the Employer and the Participant, the entire amount of reduction in any of the Participant' s taxable years does not exceed $5,000, and the reduction is made at the same time and in the same amount as the debt otherwise would have been due and collected from the Participant.

11.4. **No Interest or Earnings**

No interest or earnings of any type shall accrue, be credited or be payable on any amounts that are credited to a Participant' s Account under this Plan other than as specified in Article V, Section 5.2.

11.5. **Facility of Payment**

When a Participant entitled to benefits under the Plan is under a legal disability, or, in the Plan Administrator' s opinion, is in any way incapacitated so as to be unable to manage their financial affairs, the Plan Administrator may direct that the benefits to which such Participant otherwise would be entitled shall be made to such Participant' s legal representative, or to such other person or persons as the Plan Administrator may direct the application of the benefits for the benefit of such Participant. Any payment made in accordance with such provisions of this Article XI, Section 11.5 shall be a full and complete discharge of any liability for such payment.

11.6. **Controlling State Law**

To the extent not superseded by the laws of the United States, the laws of the State of Texas shall be controlling in all matters relating to the Plan.

11.7. **Severability**

In case any provisions of the Plan shall be held illegal or invalid for any reason, such illegality or invalidity shall not affect the remaining provisions of the Plan, and the Plan shall be construed and enforced as if such illegal and invalid provisions had never been set forth in the Plan.

11.8. **Statutory References**

All references to the Code and ERISA include reference to any comparable or succeeding provisions of any legislation, which amends, supplements or replaces such section or subsection.

11.9. **Headings**

Section headings and titles are for reference only. In the event of a conflict between a title and the content of a section, the content of the section shall control.

11.10. **Non-taxable Benefits**

It is the intention of the Company that this Plan meet all requirements of the Code so that the benefits provided be non-taxable during the period of deferral and until actual distribution is made.

Exhibit 12.1

Marathon Oil Corporation
Computation of Ratio of Earnings to Fixed Charges
TOTAL ENTERPRISE BASIS−Unaudited

(In millions)	Year Ended December 31,				
	2011	2010	2009	2008	2007
Portion of rentals representing interest, including discontinued operations	$51	$88	$77	$89	$101
Capitalized interest, including discontinued operations	208	410	441	326	214
Other interest and fixed charges, including discontinued operations	239	105	160	153	135
Total fixed charges (A)	$498	$603	$678	$568	$450
Earnings-pretax income with applicable adjustments (B)	$4,707	$4,422	$3,112	$5,181	$3,465
Ratio of (B) to (A)	9.45	7.33	4.59	9.12	7.70

Exhibit 21.1

Subsidiaries of Marathon Oil Corporation

	Company Name	Country	Region
	Alaska Transportation Service Company	United States	Delaware
*	Alba Associates LLC	Cayman Islands	
	Alba Equatorial Guinea Partnership, L.P.	United States	Delaware
*	Alba Plant LLC	Cayman Islands	
*	Albian Sands Energy Inc.	Canada	
*	Alvheim AS	Norway	
	Amethyst Calypso Pipeline LLC	United States	Delaware
*	AMPCO Marketing, L.L.C.	United States	Michigan
*	AMPCO Services, L.L.C.	United States	Michigan
	Arctic Sun Shipping Company, Ltd.	United States	Delaware
*	Atlantic Methanol Associates LLC	Cayman Islands	
*	Atlantic Methanol Production Company LLC	Cayman Islands	
	Beluga Pipe Line Company	United States	Delaware
	CIGGS LLC	United States	Delaware
	E.G. Global LNG Services, Ltd.	United States	Delaware
	Eagle Sun Company Limited	Liberia	
*	Equatorial Guinea LNG Company, S.A.	Equatorial Guinea	
*	Equatorial Guinea LNG Holdings Limited	Bahamas	
*	Equatorial Guinea LNG Operations, S.A.	Equatorial Guinea	
*	Equatorial Guinea LNG Train 1, S.A.	Equatorial Guinea	
	FWA Equipment & Mud Company, Inc.	United States	Delaware
	Glacier Drilling Company	United States	Delaware
	Globex Energy, Inc.	United States	Delaware
*	GRT, Inc.	United States	
	GTLI LLC	United States	Delaware
*	In-Depth Systems, Inc.	United States	Texas
	Indonesia Kumawa Energy Limited	Cayman Islands	
*	Kenai Kachemak Pipeline, LLC	United States	Alaska
	Kenai Nikiski Pipeline LLC	United States	Delaware
	Marathon Alaska Holding LLC	United States	Delaware
	Marathon Alaska Natural Gas Company	United States	Delaware
	Marathon Alaska Production LLC	United States	Delaware
	Marathon Alpha Holdings LLC	United States	Delaware
	Marathon Baja Limited	Cayman Islands	
	Marathon Canada Holdings Limited	Canada	Nova Scotia
	Marathon Canada Petroleum ULC	Canada	Nova Scotia
	Marathon Canadian Oil Sands Holding Limited	Canada	Alberta
	Marathon Delta Holdings Limited	Cayman Islands	
	Marathon Delta Investment Limited	Cayman Islands	
	Marathon Dutch Investment B.V.	Netherlands	
	Marathon Dutch Investment Coöperatief U.A.	Netherlands	
	Marathon Dutch Investment LLC	United States	Delaware

	Company Name	Country	Region
	Marathon E.G. Alba Limited	Cayman Islands	
	Marathon E.G. Holding Limited	Cayman Islands	
	Marathon E.G. International Limited	Cayman Islands	
	Marathon E.G. LNG Holding Limited	Cayman Islands	
	Marathon E.G. LPG Limited	Cayman Islands	
	Marathon E.G. Methanol Limited	Cayman Islands	
	Marathon E.G. Offshore Limited	Cayman Islands	
	Marathon E.G. Oil Operations Limited	Cayman Islands	
	Marathon E.G. Production Limited	Cayman Islands	
	Marathon Eagle Ford Midstream LLC	United States	Delaware
	Marathon East Texas Holdings LLC	United States	Delaware
	Marathon Exploration Tunisia, Ltd.	United States	Delaware
*	Marathon Financing Trust I	United States	Delaware
*	Marathon Financing Trust II	United States	Delaware
	Marathon Global Services, Ltd.	United States	Delaware
	Marathon Green B.V.	Netherlands	
	Marathon GTF Technology, Ltd.	United States	Delaware
	Marathon Guaranty Corporation	United States	Delaware
	Marathon Indonesia (Bone Bay) Limited	Cayman Islands	
	Marathon Indonesia (Kumawa) Limited	Cayman Islands	
	Marathon Indonesia Exploration Limited	Cayman Islands	
	Marathon Indonesia Holding Limited	Cayman Islands	
	Marathon Indonesia New Ventures Limited	Cayman Islands	
	Marathon International Oil (G.B.) Limited	United Kingdom	England and Wales
	Marathon International Oil Angola Block 31 Limited	Cayman Islands	
	Marathon International Oil Angola Block 32 Limited	Cayman Islands	
	Marathon International Oil Blanco Limited	Cayman Islands	
	Marathon International Oil Canada, Ltd.	United States	Delaware
	Marathon International Oil Company	United States	Delaware
	Marathon International Oil Holdings LLC	United States	Delaware
	Marathon International Oil Libya Limited	Cayman Islands	
	Marathon International Oil Morado Limited	Cayman Islands	
	Marathon International Oil Portfolio Coöperatief U.A.	Netherlands	
	Marathon International Oil Supply Company (G.B.) Limited	United Kingdom	England and Wales
	Marathon International Oil Turquesa Limited	Cayman Islands	
	Marathon International Oil Ukraine Holding Limited	Cayman Islands	
	Marathon International Oil Ventures Limited	Cayman Islands	
	Marathon International Petroleum Asia Pacific Limited	Cayman Islands	
	Marathon International Petroleum Indonesia Limited	Cayman Islands	
	Marathon International Services Limited	Cayman Islands	
	Marathon International Upstream, Ltd.	United States	Delaware
	Marathon LNG Marketing LLC	United States	Delaware
	Marathon Methanol Holding LLC	United States	Delaware

Company Name	Country	Region
Marathon Nigerian Ventures LLC	United States	Delaware
Marathon Norway Investment Coöperatief U.A.	Netherlands	
Marathon Norway Investment LLC	United States	Delaware
Marathon Offshore Alpha Limited	Cayman Islands	
Marathon Offshore Beta Limited	Cayman Islands	
Marathon Offshore Delta Limited	Cayman Islands	
Marathon Offshore Epsilon Limited	Cayman Islands	
Marathon Offshore Gamma Limited	Cayman Islands	
Marathon Offshore Investment Limited	Cayman Islands	
Marathon Offshore Libya Service Company, Ltd.	United States	Delaware
Marathon Oil (East Texas) L.P.	United States	Texas
Marathon Oil (West Texas) L.P.	United States	Texas
Marathon Oil Canada Corporation	Canada	Alberta
Marathon Oil Cap Bon, Ltd.	United States	Delaware
Marathon Oil Company	United States	Ohio
Marathon Oil Corporation	United States	Delaware
Marathon Oil Decommissioning Services LLC	United States	Delaware
Marathon Oil Dutch Holdings B.V.	Netherlands	
Marathon Oil Dutch Holdings Coöperatief U.A.	Netherlands	
Marathon Oil Dutch Investment C.V.	Netherlands	
Marathon Oil Eastern, Ltd.	United States	Delaware
Marathon Oil EF LLC	United States	Delaware
Marathon Oil Exploration (U.K.) Limited	United Kingdom	England and Wales
Marathon Oil Gabon LDC	Cayman Islands	
Marathon Oil Garnet Limited	Cayman Islands	
Marathon Oil Holdings (Barbados) Inc.	Barbados	
Marathon Oil Holdings U.K. Limited	United Kingdom	England and Wales
Marathon Oil Investment LLC	United States	Delaware
Marathon Oil Jenein Limited	Cayman Islands	
Marathon Oil Jupiter Limited	Cayman Islands	
Marathon Oil KDV B.V.	Netherlands	
Marathon Oil Lapis Limited	Cayman Islands	
Marathon Oil Libya Limited	Cayman Islands	
Marathon Oil Norge AS	Norway	
Marathon Oil North Sea (G.B.) Limited	United Kingdom	England and Wales
Marathon Oil Norway Holdings C.V.	Netherlands	
Marathon Oil Norway Investment LLC	United States	Delaware
Marathon Oil Poland - Area A Sp. z o.o.	Poland	
Marathon Oil Poland - Area B Sp. z o.o.	Poland	
Marathon Oil Poland - Area C Sp. z o.o.	Poland	
Marathon Oil Poland - Area D Sp. z o.o.	Poland	
Marathon Oil Poland - Area E Sp. z o.o.	Poland	

Company Name	Country	Region
Marathon Oil Poland - Area F Sp. z o.o.	Poland	
Marathon Oil Poland - Area G Sp. z o.o.	Poland	
Marathon Oil Poland - Area H Sp. z o.o.	Poland	
Marathon Oil Poland - Area I Sp. z o.o.	Poland	
Marathon Oil Poland – Area J Sp. z o.o.	Poland	
Marathon Oil Polska Sp. z o.o.	Poland	
Marathon Oil Preferred Funding, Ltd.	United States	Delaware
Marathon Oil Salmagundi, Ltd.	United States	Delaware
Marathon Oil Sands (U.S.A.) Inc.	United States	Delaware
Marathon Oil Supply Company (U.S.) Limited	United Kingdom	England and Wales
Marathon Oil Timor Gap East, Ltd.	United States	Delaware
Marathon Oil Timor Gap West, Ltd.	United States	Delaware
Marathon Oil U.K. LLC	United States	Delaware
Marathon Oil Venus Limited	Cayman Islands	
Marathon Oil West of Shetlands Limited	United Kingdom	England and Wales
* Marathon Petroleum (Syria) Ltd	Switzerland	
Marathon Petroleum Company (Norway) LLC	United States	Delaware
Marathon Petroleum Hibernia, Ltd.	United States	Delaware
Marathon Petroleum Ireland, Ltd.	United States	Delaware
Marathon Petroleum Nigeria Limited	Nigeria	
Marathon Petroleum Swiss Holdings LLC	Switzerland	
Marathon Petroleum Switzerland B.V.	Netherlands	
Marathon Portfolio International Limited	Cayman Islands	
Marathon Service (G.B.) Limited	United Kingdom	England and Wales
Marathon Service Company	United States	Delaware
Marathon Upstream Gabon, Ltd.	United States	Delaware
Marathon Upstream North Sea (G.B.) Limited	United Kingdom	England and Wales
Marathon Upstream U.K. LLC	United States	Delaware
Marathon US Holdings Inc.	United States	Delaware
Marathon West Texas Holdings LLC	United States	Delaware
Marathon Western Saudi Arabia Limited	Cayman Islands	
Miltiades Limited	United Kingdom	England and Wales
MOC Portfolio Delaware, Inc.	United States	Delaware
MP Ukraine Holding Limited	Cyprus	
MWV Gas Gathering, Inc.	United States	Delaware
Navatex Gathering LLC	United States	Delaware
Old Main Assurance Ltd.	Bermuda	
* Palmyra Petroleum Company	Syrian Arab Republic	
Pan Ocean Energy Company	United States	Delaware
Pennaco Energy, Inc.	United States	Delaware
Pheidippides Finance B.V.	Netherlands	

Company Name	Country	Region
Polar Eagle Shipping Company, Ltd.	United States	Delaware
Red Butte Pipe Line Company	United States	Delaware
Seaborn Properties LLC	United States	Delaware
Tarragon Resources (U.S.A.) Inc.	United States	Delaware
Texas Oil & Gas Corp.	United States	Delaware
Western Bluewater Resources (Trinidad) Limited	Trinidad and Tobago	
Yorktown Assurance Corporation	United States	Vermont

* Indicates a company that is not wholly owned directly or indirectly by Marathon Oil Corporation

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements listed below of Marathon Oil Corporation of our report dated February 29, 2012 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

On Form S-3ASR:		Relating to:
File No.	333-146772	Common Stock
	333-168171	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
	333-157824	Dividend Reinvestment and Direct Stock Purchase Plan
On Form S-8:		Relating to:
File No.	33-56828	Marathon Oil Company Thrift Plan
	333-29699	1990 Stock Plan
	333-29709	Marathon Oil Company Thrift Plan
	333-52751	1990 Stock Plan
	33-41864	1990 Stock Plan
	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 29, 2012

EXHIBIT 23.2

[Letterhead of GLJ Petroleum Consultants LTD]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERING CONSULTANTS

Re: Marathon Oil Corporation

We hereby consent to the references in this Annual Report on Form 10-K of Marathon Oil Corporation ("the Company"), to our reserve reports relating to the estimated quantities of proved reserves of oil, gas and synthetic crude oil, net to the Company' s interest. We also consent to the incorporation by reference of such reports in the Registration Statements indicated below.

Form S-3ASR:	Relating to:	
Reg. No.	333-146772	Common Stock
	333-168171	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
	333-157824	Dividend Reinvestment and Direct Stock Purchase Plan
Form S-8:	Relating to:	
Reg. No.	33-56828	Marathon Oil Company Thrift Plan
	333-29699	1990 Stock Plan
	333-29709	Marathon Oil Company Thrift Plan
	333-52751	1990 Stock Plan
	33-41864	1990 Stock Plan
	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.

/s/ James H. Willmon, P.Eng.

James H. Willmon, P. Eng.
Vice-President

Calgary, Alberta CANADA
February 29, 2012

EXHIBIT 23.3

[Letterhead of Ryder Scott Company, L.P.]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references in this Annual Report on Form 10-K of Marathon Oil Corporation ("the Company"), to our summary reports on audits of the estimated quantities of certain proved reserves of oil and gas, net to the Company' s interest, and to such report and this consent being filed as exhibits to this Form 10-K. We also consent to the incorporation by reference of such reports in the Registration Statements indicated below.

Form S-3ASR:	Relating to:	
Reg. No.	333-146772	Common Stock
	333-168171	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
	333-157824	Dividend Reinvestment and Direct Stock Purchase Plan
Form S-8:	Relating to:	
Reg. No.	33-56828	Marathon Oil Company Thrift Plan
	333-29699	1990 Stock Plan
	333-29709	Marathon Oil Company Thrift Plan
	333-52751	1990 Stock Plan
	33-41864	1990 Stock Plan
	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 29, 2012

EXHIBIT 23.4

[Letterhead of Netherland, Sewell & Associates, Inc.]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references in this Annual Report on Form 10-K of Marathon Oil Corporation (“the Company”), to our summary report on the estimated quantities of certain proved reserves of oil and gas, net to the Company’ s interest, as of December 31, 2008, and to such report and this consent being filed as exhibits to this Form 10-K. We also consent to the incorporation by reference of such reports in the Registration Statements indicated below.

Form S-3ASR:	Relating to:	
Reg. No.	333-146772	Common Stock
	333-168171	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
	333-157824	Dividend Reinvestment and Direct Stock Purchase Plan
Form S-8:	Relating to:	
Reg. No.	33-56828	Marathon Oil Company Thrift Plan
	333-29699	1990 Stock Plan
	333-29709	Marathon Oil Company Thrift Plan
	333-52751	1990 Stock Plan
	33-41864	1990 Stock Plan
	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 29, 2012

Exhibit 31.1

MARATHON OIL CORPORATION

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Clarence P. Cazalot, Jr., certify that:

1. I have reviewed this report on Form 10-K of Marathon Oil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant' s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant' s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant' s internal control over financial reporting that occurred during the registrant' s most recent fiscal quarter (the registrant' s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant' s internal control over financial reporting; and

5. The registrant' s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant' s auditors and the audit committee of the registrant' s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant' s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant' s internal control over financial reporting.

Date: February 29, 2012

/s/ Clarence P. Cazalot, Jr.

Clarence P. Cazalot, Jr.
Chairman, President and Chief Executive Officer

Exhibit 31.2

MARATHON OIL CORPORATION

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Janet F. Clark, certify that:

1. I have reviewed this report on Form 10-K of Marathon Oil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant' s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant' s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant' s internal control over financial reporting that occurred during the registrant' s most recent fiscal quarter (the registrant' s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant' s internal control over financial reporting; and

5. The registrant' s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant' s auditors and the audit committee of the registrant' s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant' s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant' s internal control over financial reporting.

Date: February 29, 2012

/s/ Janet F. Clark

Janet F. Clark
Executive Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Marathon Oil Corporation (the "Company") on Form 10-K for the period ending December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Clarence P. Cazalot, Jr., Chairman, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 29, 2012

/s/ Clarence P. Cazalot, Jr.

Clarence P. Cazalot, Jr.
Chairman, President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Marathon Oil Corporation (the "Company") on Form 10-K for the period ending December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Janet F. Clark, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 29, 2012

/s/ Janet F. Clark

Janet F. Clark
Executive Vice President and Chief Financial Officer

Exhibit 99.1

GLJ Petroleum Consultants

Principal Officers:
Keith M. Braaten, P. Eng.
President & CEO
Jodi L. Anhorn, P. Eng.
Executive Vice President & COO

Officers / Vice Presidents:
Terry L. Aarsby, P. Eng.
Carolyn P. Bennett, P. Eng.
Leonard L. Herchen, P. Eng.
Myron J. Hladyshevsky, P. Eng.
Bryan M. Joa, P. Eng.
Mark Jobin, P. Geol.
John E. Keith, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

January 31, 2012

Project 1111045

The Board of Directors of Marathon Oil Corporation
Marathon Oil Corporation
2400, 440 - 2nd Avenue SW
Calgary, AB T2P 5E9

Dear Board Members:

Re: <u>Third Party Report on Reserves</u>

This report was prepared to satisfy requirements contained in Item 1202(a)(8) of U.S. Securities and Exchange Commission Regulation S-K and to provide the qualifications of the technical persons responsible for overseeing the reserve estimation process.

The numbering of items below corresponds to the requirements set out in Item 1202(a)(8) of Regulation S-K. Terms to which a meaning is ascribed in *Regulation S-K* and *Regulation S-X* have the same meaning in this report.

i. We have prepared an independent evaluation of the Canadian mineable oil sands reserves of Marathon Oil Corporation (the "Company") for the management and the board of directors of the Company. The primary purpose of our evaluation report was to provide estimates of reserves information in support of the Company' s year-end reserves reporting requirements under US Securities Regulation S-K and for other internal business and financial needs of the Company.

ii. We have evaluated and reviewed certain reserves of the Company as at December 31, 2011. The completion (transmittal) date of our report is January 31, 2012.

iii. The following table sets forth the total proved net after royalty reserves under constant prices and costs covered by our report by geographic area, and the proportion of the Company covered.

Location	Oil and NGL MMbbl	Natural Gas Bcf	Synthetic Crude Oil[1] MMbbl	Oil Equivalent[2] MMbbl
Canada			623	623
Total Company Reserves[3]	733	2,666	623	1,800
Portion of Total Covered	0 %	0 %	100 %	35 %

Notes1) Total sales less blendstocks, after upgrading AOSP mined bitumen.
2) Oil equivalence factors: Crude Oil, NGL & SCO 1 bbl/bbl, Natural Gas 6 Mcf/bbl
3) Supplied by the company to derive portion of total covered by GLJ

The Company provided to us the total Company reported reserves to derive the portion evaluated by GLJ. We express no opinion on this portion of the Company' s reserves that we did not evaluate.

iv. Our report covered 100 percent of the Company' s mineable, synthetic crude oil (SCO) reserves; our evaluation coverage from the perspective of the Company' s total reserves is provided above in item iii. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements under the U.S. Securities and Exchange Commission ("SEC requirements").

The royalty obligations on the evaluated oil sands property, the Athabasca Oil Sands Project (AOSP), are determined upstream, on a bitumen basis. There are two royalty projects, one for Muskeg River Mine operations and one for Jackpine Mine operations. The synthetic crude oil (SCO) reserves reflect both the upgrading yield on bitumen and product value differences between SCO and bitumen. As a consequence of differences in revenue, the royalty rate for SCO is lower than it is on bitumen. No reserves are attributed to internally produced products that are consumed as fuel.

The economic evaluation was prepared to reflect the net present value of Marathon Oil Canada Corporation (MOCC) before any incremental US taxes or overhead. Canadian income taxes were included, as well as MOCC supplied estimates of Calgary Office overhead and abandonment and reclamation obligations.

Data used in our evaluation were obtained from regulatory agencies, public sources and from Company personnel and Company files. In the preparation of our report we have accepted as presented, and have relied, without independent verification, upon a variety of information furnished by the Company such as interests and burdens, recent production, product transportation and marketing and sales agreements, historical revenue, capital costs, operating expense data, budget forecasts, capital cost estimates and well data for recently drilled wells. If in the course of our evaluation, the validity or sufficiency of any material information was brought into question, we did not rely on such information until such concerns were satisfactorily resolved.

The Company has warranted in a representation letter to us that, to the best of the Company' s knowledge and belief, all data furnished to us was accurate in all material respects, and no material data relevant to our evaluation was omitted.

GLJ toured the AOSP mine and facilities on November 21, 2011.

In our opinion, estimates provided in our report have, in all material respects, been determined in accordance with the applicable industry standards, and results provided in our report and summarized herein are appropriate for inclusion in filings under Regulation S-K.

v. As required under SEC Regulation S-K, reserves are those quantities of oil and gas that are estimated to be economically producible under existing economic conditions. As specified, in determining economic production, constant product reference prices have been based on a 12 month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12 month period prior to the effective date of our report. In our economic analysis, operating and capital costs are those costs estimated as applicable at the effective date of our report, with no future escalation. Where deemed appropriate, the capital costs and revised operating costs associated with the implementation of committed projects designed to modify specific field operations in the future may be included in economic projections.

vi. Our report has been prepared assuming the continuation of existing regulatory and fiscal conditions subject to the guidance in the COGE Handbook and SEC regulations. Notwithstanding that the Company currently has regulatory approval to produce the reserves identified in our report, there is no assurance that changes in regulation will not occur; such changes, which cannot reliably be predicted, could impact the Company' s ability to recovery the estimated reserves.

vii. Oil and gas reserves estimates have an inherent degree of associated uncertainty, the degree of which is affected by many factors. Reserves estimates will vary due to the limited and imprecise nature of data upon which the estimates of reserves are predicated. Moreover, the methods and data used in estimating reserves are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons involved in the preparation of reserves estimates and associated information are required, in applying geosciences, engineering and evaluation principles, to make numerous unbiased judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserves estimates inherently imprecise. Reserves estimates may change substantially as additional data becomes available and as economic conditions impacting oil and gas prices and costs change. Reserves estimates will also change over time due to other factors such as knowledge and technology, fiscal and economic conditions, and contractual, statutory and regulatory provisions.

viii. In our opinion, the reserves information evaluated by us have, in all material respects, been determined in accordance with all appropriate industry standards, methods and procedures applicable for the filing of reserves information under U.S. SEC Regulation S-K.

ix. A summary of the Company reserves evaluated by us was provided for item iii. All of the reserves evaluated by us are developed.

GLJ is a private firm established in 1972 whose business is the provision of independent geological and engineering services to the petroleum industry. GLJ is among the largest evaluation firms in North America with approximately 70 professional engineering and geoscience personnel. GLJ evaluate the reserves of the four producing oil sands mining operations for various owners. Mr. Willmon and Mr. Freeborn conducted the evaluation. Both individuals are qualified, independent reserves evaluators as defined in COGEH, and are registered Practicing Professional Engineers in the Province of Alberta. Mr. Willmon has in excess of 32 years of practical experience in petroleum engineering, has been employed at GLJ as an evaluator/auditor since 1982, and has been involved in evaluations of surface mineable oil sands reserves since 1986. Mr. Freeborn has in excess of 11 years of practical experience in petroleum engineering, and has been employed at GLJ as an evaluator/auditor since 1999.

We trust this meets your current requirements.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"ORIGINALLY SIGNED BY"

Tim R. Freeborn, P. Eng.

"ORIGINALLY SIGNED BY"

James H Willmon, P. Eng.
Vice President

TRF/JHW/ljn
Attachment

Exhibit 99.4

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 22, 2012

Marathon Oil Corporation
5555 San Felipe Road
Houston, Texas 77056

Ladies and Gentlemen:

In accordance with your request, we have prepared a reserves certification and deliverability analysis, as of December 31, 2010, of Alba Field, located offshore Equatorial Guinea. Pursuant to the terms of the Gas Purchase and Sales Agreement (GPSA) between the Alba Field Production Sharing Contract (PSC) contractors (referred to herein as the "Alba Field owners") and Atlantic Methanol Production Company (AMPCO), the primary purpose of this report is to verify that there are (1) sufficient proved reserves in Alba Field to cover delivery of gas from the Alba Field owners to AMPCO equal to 100 percent of the stated maximum daily quantities over the remaining term of the GPSA that ends May 3, 2026, and (2) sufficient proved developed (PD) reserves in Alba Field to deliver, for a period of five years, 102 percent of the maximum daily contract quantity. For the purposes of this report, the maximum daily contract quantity is 135,000 million British thermal units (MMBTU) per day, or 140 million cubic feet of gas per day (MMCFD). Economic analysis was performed only to confirm economic producibility and determine economic limits for the properties. Monetary values shown in this report are expressed in United States dollars (US$). For each reserves category, the economic life of the field is either the economic limit or the end of the GPSA, May 3, 2026, whichever is earliest.

We completed our evaluation on April 21, 2011. It is our understanding that Marathon Oil Corporation's (Marathon's) share of the gross (100 percent) proved reserves estimated in this report constituted approximately 24 percent of all proved reserves owned by Marathon, as of December 31, 2010. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities−Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Marathon's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose, provided that, as required by the SEC, Marathon lists its net interest after application of the PSC terms.

Primary condensate separation occurs offshore for Alba Field. The condensate and remaining gas streams are sent to onshore processing facilities at Punta Europa where the condensate is stabilized, liquefied petroleum gas (LPG) is extracted from the gas stream in the LPG plant, and remaining gas is sent to both the methanol and liquefied natural gas (LNG) plants with excess gas being reinjected offshore. Phase 3 of the Alba Field development plan was the LNG plant project, which was completed in 2006. In 2007, the LNG plant was commissioned and Marathon ramped up gas sales to the plant while reducing gas injection rates. In 2010, a dehydration modification project was completed onshore in Plant 3, which increased the gas throughput capacity of all onshore facilities combined to 990 MMCFD. During 2010, sales to the LNG plant averaged 616 MMCFD and sales to the methanol plant averaged 108 MMCFD. In the fourth quarter of 2010, average production from the 12 producing Alba Field wells was 965 MMCFD, with associated condensate, and approximately 60 MMCFD was reinjected offshore.

We estimate the gross (100 percent) reserves in Alba Field, as of December 31, 2010, to be:

	Gross (100 Percent) Reserves		
	Gas	Condensate	LPG
Category	(BCF)	(MMBBL)	(MMBBL)

Proved Developed (PD)	2,033	110	51
Proved (1P)	3,149	155	77

Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases. Condensate and LPG volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of proved undeveloped reserves included in this report are dependent on an offshore compression project that is not required until 2015 because of plant capacity constraints. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves included herein have not been adjusted for risk. In this report, we have attributed estimated gas sales volumes and LPG reserves to Alba Field, even though the LPG plant is separate from the field facilities. This designation is based on our interpretation of the agreement between the Alba Field owners and the LPG plant owners that states that title to the feedstock gas sales volumes and LPG liquids is transferred from the Alba Field owners at the tailgate of the LPG plant and that those volumes are valued on an MMBTU basis. It is our understanding that this interpretation is consistent with Marathon's internal reserves booking practice for Alba Field.

In order to satisfy the primary objective of this report, we made certain assumptions regarding future field production and injection rates. The most significant assumption pertains to the rate of Alba Field gas consumption by the LNG plant. Three LNG plant consumption scenarios have been used: a low-take case, a mid-take case, and a high-take case. The LNG plant low-take case is 560 MMCFD, the mid-take case is 600 MMCFD, and the high-take case is 640 MMCFD. The estimates of reserves shown in this report are based on the low-take case.

For all cases presented in this report, we have limited the supply of gas to the LNG plant following the supply plateau period to ensure that supply obligations to the AMPCO methanol plant can be met. We have determined that if the LNG plant receives gas as described in the low-take case, there are sufficient proved reserves to supply the AMPCO methanol plant until termination of the GPSA. If the LNG plant receives gas as described in the mid-take case until it is no longer economic to operate, we estimate that there will be a shortfall of proved reserves to supply the AMPCO methanol plant in 2026. If the LNG plant receives gas as described in the high-take case until it is no longer economic to operate, we estimate that there will be a shortfall of proved reserves to supply the AMPCO methanol plant in 2025 and 2026. We have also determined that there are sufficient PD reserves to satisfy the requirement to supply the AMPCO methanol plant with 102 percent of the maximum daily contract quantity for a period of five years.

For our study, we had access to certain data and analyses provided by Marathon that were initially presented to us in various reviews and meetings held from June through September 2003. We have received updated data on an annual basis for the purposes of performing an audit of Alba Field reserves on behalf of Noble Energy, Inc. In February 2011, Marathon presented an additional update of Alba Field, including development plans and a review of their latest analyses. The information and data received to date include, but are not limited to, a geological and geophysical review of Marathon's interpretation of the Alba Field area, limited structure and amplitude maps, formation test results and fluid gradient analysis, petrophysical methodology, fluid property analysis methodology, and potential future development plans. We were provided a digital backup of a Landmark OpenWorks project (3-D seismic data), multiple interpreted seismic horizons, routine and special core analysis data, pressure data, fluid and laboratory analysis reports and subsequent fluid property analysis, digital log data, capillary pressure data, and historical production data.

Our study is an update of previous work that consisted of (1) a geophysical and geological review of the Alba Reservoir; (2) a review of structure and generation of gross isopach maps; (3) a petrophysical analysis of net hydrocarbon pay, porosity, and connate water saturation; (4) a review of pressure and temperature properties as well as fluid properties using existing fluid laboratory analysis and black oil correlations; (5) the generation of proved estimates of wet gas-in-place, dry gas-in-place, condensate-in-place, and LPG-in-place; (6) a reservoir simulation to derive estimates of dry gas, condensate, and LPG recoveries; (7) a review of contractual sales and deliverability obligations for Alba Field, the Alba LPG plant, the LNG plant, and the methanol plant; (8) the generation of production profiles for primary and secondary condensate, LPG, offshore and onshore fuel and flare gas, gas used by the LPG and methanol plants, and remaining gas available for the LNG plant; and (9) a review of economic terms of the Alba PSC and LPG plant contracts. For this study, we have incorporated new production and pressure data into the simulation history matching process and the latest development plans into the simulation prediction cases.

Gas, condensate, and LPG prices were used only to confirm economic producibility and determine economic limits for the properties. The gas price used is the fixed contract price of US$0.25 per MMBTU and is adjusted for energy content. Condensate and LPG prices are based on the 12-month unweighted arithmetic average of the first-day-of-the-month Wall Street Journal West Texas Intermediate spot price for each month in the period January through December 2010. The average price of US$79.43 per barrel is adjusted for quality and a regional price differential. The average adjusted product prices of US$0.295 per MCF of gas, US$72.89 per barrel of condensate, and US$45.42 per barrel of LPG are held constant throughout the lives of the properties.

Operating costs and capital costs were used only to confirm economic producibility and determine economic limits for the properties. Operating costs used in this report are based on operating expense records of Marathon, the operator of the properties. As requested, operating costs are limited to direct platform-, plant-, and field-level costs and Marathon's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs are held constant throughout the lives of the properties. Capital costs are included as required for workovers, new development wells, and production equipment. The future capital costs are held constant to the date of expenditure.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts used to confirm economic producibility and determine economic limits for the properties. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

NETHERLAND, SEWELL & ASSOCIATES, INC.

The data used in our estimates were obtained from Marathon and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The contractual rights to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ John R. Cliver
John R. Cliver, P.E. 107216
Petroleum Engineer

Date Signed: February 22, 2012

By: /s/ Patrick L. Higgs
Patrick L. Higgs, P.G. 985
Vice President

Date Signed: February 22, 2012

JRC:JLM

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities−Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible−from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations−prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities–Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*

b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*

b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*

c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the* *entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*

d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects − such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations − by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);

The company's historical record at completing development of comparable long-term projects;

The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;

The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and

The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.5

MARATHON OIL CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2010

\s\ Jeffrey D. Wilson
Jeffrey D. Wilson, P.E.
TBPE License No. 86426
Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235
FAX (713) 651-0849
TELEPHONE (713) 651-9191

February 17, 2012

Marathon Oil Corporation
5555 San Felipe
P.O. Box 3128
Houston, TX 77253-3128

Gentlemen:

At the request of Marathon Oil Corporation (Marathon), Ryder Scott Company (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2010 prepared by Marathon' s engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party reserves audit, completed on November 9, 2011 and presented herein, was prepared for public disclosure by Marathon in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent Marathon' s estimated net reserves attributable to the leasehold and royalty in certain properties owned by Marathon and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2010. The properties reviewed by Ryder Scott incorporate Marathon reserve determinations and are located in the states of New Mexico, North Dakota and Texas and in the United Kingdom waters offshore in the North Sea.

The properties reviewed by Ryder Scott account for a portion of Marathon' s total net proved reserves as of December 31, 2010. Based on the estimates of total net proved reserves prepared by Marathon, the reserves audit conducted by Ryder Scott addresses 12 percent of the total proved developed net liquid hydrocarbon reserves, one percent of the total proved developed net gas reserves, 31 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 2 percent of the total proved undeveloped net gas reserves of Marathon.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities."

Based on our review, including the data, technical processes and interpretations presented by Marathon, it is our opinion that the overall procedures and methodologies utilized by Marathon in preparing their estimates of the proved reserves as of December 31, 2010 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Marathon are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Marathon has informed us that in the preparation of their reserve and income projections, as of December 31, 2010, they used average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Marathon attributable to Marathon' s interest in properties that we reviewed are summarized as follows:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold and Royalty Interests of
Marathon Oil Corporation
As of December 31, 2010

	Proved		
	Developed	Undeveloped	Total Proved
Net Reserves of Properties Audited by Ryder Scott			
Oil/Condensate–MBarrels	58,262	47,526	105,788
Gas - MMCF	19,219	15,920	35,139
MMBOE	61,446	50,179	111,645

Liquid hydrocarbons are expressed in thousands of standard 42 gallon barrels (MBarrels). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net remaining reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MMBOE means million barrels of oil equivalent.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission' s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Definitions" in this report. The proved reserves included herein consist of the developed and undeveloped categories.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Marathon' s request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission' s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated primarily by performance-based methods and analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve and other production analysis such as cumulative percent hydrocarbon pore volume of CO_2 injection versus cumulative percent of OOIP recovered plot. These analyses utilized extrapolations of historical production data available through December 2010 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Marathon or obtained from public data sources and were considered sufficient for the purpose thereof.

The remaining proved developed (non-producing) and all of the undeveloped reserves included herein were estimated by analogy to the historical performance of mature areas within each unit or field where these analogues were applied. In the United Kingdom assets, these volumes were confirmed with volumetrics. Data was furnished to Ryder Scott by Marathon or obtained from public data sources that were available through December 2010. The data utilized from the analogues as well as the seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

Essentially all of the reserves included herein attributable to the fields in New Mexico and Texas are produced through application of improved recovery techniques (CO_2 injection). The estimates of our proved undeveloped reserves are attributable to the application of CO_2 injection which has been proved effective by actual projects producing in the same reservoir.

The fields located in North Dakota are oil shales and are developed almost entirely using horizontal drilling technology.

To estimate economically recoverable proved oil and gas reserves, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Marathon relating to hydrocarbon prices and costs as noted herein.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

The hydrocarbon prices furnished by Marathon for the properties reviewed by us and as required by Regulation S-K Item 1202(8)(v) are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2010 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. The product prices which were actually used by Marathon to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon.

Information relating to Marathon' s average sales prices for the geographic areas reviewed by us is disclosed in the table entitled "Average Sales Price per Unit" in Marathon' s Form 10-K for the fiscal year ended December 31, 2010.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Marathon' s individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserve estimates reviewed. The proved gas volumes included herein do not attribute gas consumed in operations as reserves.

Operating costs furnished by Marathon are based on the operating expense reports of Marathon and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For certain unitized leases per unit costs of CO_2 production are included. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements**.** Where applicable operating costs were included for transportation, tariffs and/or processing fees. The operating costs furnished by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Marathon are based on authorizations for expenditure for the proposed work or actual costs for similar projects. For the United Kingdom properties, the development costs furnished by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon.

The proved developed (non-producing) and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Marathon’ s plans to develop these reserves as of December 31, 2010. The implementation of Marathon’ s development plans as presented to us is subject to the approval process adopted by Marathon’ s management. As the result of our inquiries during the course of our review, Marathon has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Marathon’ s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Marathon. Additionally, Marathon has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs used by Marathon were held constant throughout the life of the properties.

Marathon’ s forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Marathon to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Marathon. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Marathon’ s estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

The proved reserves reported herein are limited to the period prior to expiration of current contracts providing the legal right to produce or a revenue interest in such production unless evidence indicates that contract renewal is reasonably certain. Furthermore, properties in the different countries may be subjected to significantly varying contractual fiscal terms that affect the net revenue to Marathon for the production of these volumes. The prices and economic return received for these net volumes can vary significantly based on the terms of these contracts. Therefore, when applicable, Ryder Scott reviewed the fiscal terms of such contracts and discussed with Marathon the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Marathon’ s representations regarding such contractual information should be construed as a legal opinion on this matter.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Marathon operates or has interests. Marathon' s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Marathon owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Marathon for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Marathon are responsible for the preparation of reserve estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Marathon has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Marathon' s forecast of future proved production, we have relied upon data furnished by Marathon with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Marathon. We consider the factual data furnished to us by Marathon to be appropriate and sufficient for the purpose of our review of Marathon' s estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Marathon and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Marathon, it is our opinion that the overall procedures and methodologies utilized by Marathon in preparing their estimates of the proved reserves as of December 31, 2010 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Marathon are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

We were in reasonable agreement with Marathon' s estimates of proved reserves for the properties which we reviewed. As a consequence, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by Marathon.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer' s license or a registered or certified professional geoscientist' s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Marathon. Neither we nor any of our employees have any interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Marathon.

Marathon makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Marathon has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Marathon of the references to our name as well as to the references to our third party report for Marathon, which appears in the December 31, 2010 annual report on Form 10-K of Marathon. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Marathon.

We have provided Marathon with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Marathon and the original signed report letter, the original signed report letter shall control and supersede the digital version.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Jeffrey D. Wilson

Jeffrey D. Wilson, P.E.
TBPE License No. 86426
Senior Vice President

[SEAL]

JDW (JEH)/pl

Professional Qualifications of Primary Technical Engineer

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Jeffrey D. Wilson was the primary technical person responsible for the estimate of the reserves, future production and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1998, is a Senior Vice President and also serves as a member of the Board of Directors responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Exxon. For more information regarding Mr. Wilson' s geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Wilson earned a Bachelor of Science degree in Mechanical Engineering from the University of Houston in 1991, graduating with Magna Cum Laude honors, and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and currently serves as a member of the SPE Oil and Gas Reserves Committee.

The Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills. As part of his 2011 continuing education hours, Mr. Wilson attended an internally presented 6 hours of formalized training and 24 hours of formalized external training on various topics including SEC oil and gas reporting requirements, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, overviews of the various productive basins, evaluations of resource play reserves, petroleum economics evaluation methods and software, and ethics training. Mr. Wilson also taught multiple classes throughout the year for a total of 12 hours class time on advanced economic modeling techniques and production sharing contract modeling.

Based on his educational background, professional training and more than 20 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible–from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations–prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:

RULE 4-10(a) of REGULATION S-X PART 210

UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)

Sponsored and Approved by:

SOCIETY OF PETROLEUM ENGINEERS (SPE)

WORLD PETROLEUM COUNCIL (WPC)

AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)

SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate, but which have not started producing;

(2) wells which were shut-in for market conditions or pipeline connections; or

(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Income Taxes (Tables)

12 Months Ended Dec. 31, 2011

Income Taxes Note Tables [Abstract]

Income Tax Provisions (Benefits)

(In millions)	2011 Current	2011 Deferred	2011 Total	2010 Current	2010 Deferred	2010 Total	2009 Current	2009 Deferred	2009 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

Reconciliation of Federal Statutory Income Tax Rate to Provision for Income Taxes

	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%

Deferred Tax Assets and Liabilities

(In millions)	December 31, 2011	December 31, 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	0	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.

Net Deferred Tax Assets Liabilities

(In millions)	December 31, 2011	December 31, 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

Income Tax Returns Remaining Subject to Examination

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

Summary of 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	0	(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

Acquisitions (Details) (Eagle Ford Acquistion [Member], USD $) In Billions, unless otherwise specified	12 Months Ended Dec. 31, 2011 acres
Eagle Ford Acquistion [Member]	
Asset acquisition [Line Items]	
Acquisition Costs, Period Cost	$ 4.50
Gas and oil acreages undeveloped and developed net	167,000

Supplemental Cash Flow Information (Tables)

12 Months Ended Dec. 31, 2011

Supplemental Cash Flow Information Note Details [Abstract]

Schedule of interest paid, income taxes paid, and significant noncash items

(In millions)		2011		2010		2009
Net cash provided from operating activities included:						
Interest paid (net of amounts capitalized)	$	268	$	107	$	19
Income taxes paid to taxing authorities		2,893		2,155		1,663
Commercial paper and revolving credit arrangements, net:						
Commercial paper - issuances	$	421	$	-	$	897
- repayments		(421)		-		(897)
Total	$	-	$	-	$	-
Noncash investing and financing activities related to continuing operations:						
Additions to property, plant and equipment						
Asset retirement costs capitalized, excluding acquisitions	$	151	$	207	$	135
Change in capital expenditure accrual		104		(140)		(28)
Debt payments made by United States Steel		214		105		144
Capital lease and sale-leaseback financing obligations increase		-		-		9

Property, Plant and Equipment (Details 3) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Increase (Decrease) in Capitalized Exploratory Well Costs that are Pending Determination of Proved Reserves [Roll Forward]			
Deferred exploratory well costs, beginning balance	$ 657	$ 829	$ 917
Capitalized Exploratory Well Cost, Additions Pending Determination of Proved Reserves	670	329	155
Capitalized Exploratory Well Cost, Charged to Expense	(268)	(83)	(32)
Reclassification To Well Facilities And Equipment Based On Determination Of Proved Reserves	(279)	(54)	(211)
Capitalized exploratory well cost period increase decrease for sold assets	(76)	(364)	0
Capitalized Exploratory Well Costs, Ending Balance	$ 704	$ 657	$ 829

Acquisitions (Details - Business Comb) (USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011 acres
Business Acquisition, Purchase Price Allocation [Abstract]	
Business Acquisition, Purchase Price Allocation, Current Assets, Receivables	$ 40
Business Acquisition, Purchase Price Allocation, Current Assets, Inventory	4
Business Acquisition, Purchase Price Allocation, Current Assets, Prepaid Expense and Other Assets	30
Business Acquisition, Purchase Price Allocation, Current Assets, Total	74
Business Acquisition, Purchase Price Allocation, Property, Plant and Equipment	4,501
Business Acquisition, Purchase Price Allocation, Noncurrent Assets	21
Business Acquisition, Purchase Price Allocation, Assets Acquired	4,596
Business Acquisition, Purchase Price Allocation, Current Liabilities, Accounts Payable	101
Business Acquisition, Purchase Price Allocation, Current Liabilities, Other Liabilities	20
Business Acquisition, Purchase Price Allocation, Current Liabilities, Total	121
Business Acquisition, Purchase Price Allocation, Other Noncurrent Liabilities	5
Business Acquisition, Purchase Price Allocation, Liabilities Assumed	126
Business Acquisition, Purchase Price Allocation, Assets Acquired (Liabilities Assumed), Net, Total	4,470
Eagle Ford [Member]	
Business Acquisition [Line Items]	
Gas and oil acreages undeveloped and developed net	108,000
Business Acquisition, Cost of Acquired Entity, Cash Paid	$ 265
Business acquisition discount factor	11.00%

Debt (Details) (USD $)	12 Months Ended Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Debt Instrument [Line Items]			
Loss on early extinguishment of debt	$ (279,000,000)	$ (92,000,000)	$ 0
Debt Extinguished Percent Of Face Value	112.00%	117.00%	
Unamortized fair value differential for debt assumed in acquisitions	0	16,000,000	
Unamortized discount	10,000,000	16,000,000	
Fair value adjustments	32,000,000	42,000,000	
Long-term debt due within one year	141,000,000	295,000,000	
Debt Immediately Due If Change In Control	431,000,000		
Long Term Debt By Maturity Abstract			
Debt due year 1	141,000,000		
Debt due year 2	205,000,000		
Debt due year 3	68,000,000		
Debt due year 4	68,000,000		
Debt due year 5	0		
Outstanding Short Term Debt [Abstract]			
Commercial paper outstanding	0		
Borrowings against revolving credit facility outstanding	0		
Revolving credit facility borrowing capacity	3,000,000,000		
Portion of revolving credit facility terminating in May 2013	2,625,000,000		
Portion of revolving credit facility terminating in May 2012	375,000,000		
Variable facility fee on commitment	0.10%		
United States Steel Industrial Revenue Bond Balance Current Maturity		221,000,000	
Notes Due 2012 [A] [Member]			
Debt Instrument [Line Items]			
Long-term debt	0	450,000,000	
Year of debt maturity	2012		
Stated interest rate on long-term debt	6.125%		
Notes Due 2012 [B] [Member]			
Debt Instrument [Line Items]			
Long-term debt	0	400,000,000	
Year of debt maturity	2012		
Stated interest rate on long-term debt	6.00%		
Notes Due 2018 [Member]			
Debt Instrument [Line Items]			
Long-term debt	854,000,000	894,000,000	
Year of debt maturity	2018		
Stated interest rate on long-term debt	5.90%		
Notes Due 2032 [Member]			
Debt Instrument [Line Items]			

Long-term debt	550,000,000	550,000,000
Year of debt maturity	2032	
Stated interest rate on long-term debt	6.80%	
Debentures Due 2012 [Member]		
Debt Instrument [Line Items]		
Long-term debt	53,000,000	53,000,000
Year of debt maturity	2012	
Stated interest rate on long-term debt	9.375%	
Debentures Due 2013 [Member]		
Debt Instrument [Line Items]		
Long-term debt	114,000,000	114,000,000
Year of debt maturity	2013	
Stated interest rate on long-term debt	9.125%	
Debentures Due 2014 [Member]		
Debt Instrument [Line Items]		
Long-term debt	0	700,000,000
Year of debt maturity	2014	
Stated interest rate on long-term debt	6.50%	
Debentures Due 2019 [Member]		
Debt Instrument [Line Items]		
Long-term debt	228,000,000	688,000,000
Year of debt maturity	2019	
Stated interest rate on long-term debt	7.50%	
Debentures Due 2017 [Member]		
Debt Instrument [Line Items]		
Long-term debt	682,000,000	682,000,000
Year of debt maturity	2017	
Stated interest rate on long-term debt	6.00%	
Debentures Due 2022 [Member]		
Debt Instrument [Line Items]		
Long-term debt	32,000,000	32,000,000
Year of debt maturity	2022	
Stated interest rate on long-term debt	9.375%	
Debentures Due 2023 [Member]		
Debt Instrument [Line Items]		
Long-term debt	70,000,000	70,000,000
Year of debt maturity	2023	
Stated interest rate on long-term debt	8.50%	
Debentures Due 2023 [B] [Member]		
Debt Instrument [Line Items]		
Long-term debt	131,000,000	131,000,000
Year of debt maturity	2023	
Stated interest rate on long-term debt	8.125%	
Debentures Due 2037 [Member]		

Debt Instrument [Line Items]		
Long-term debt	750,000,000	750,000,000
Year of debt maturity	2037	
Stated interest rate on long-term debt	6.60%	
Promissory Note [Member]		
Debt Instrument [Line Items]		
Long-term debt	272,000,000	340,000,000
Year of debt maturity	2012 - 2015	
Stated interest rate on long-term debt	4.55%	
Series Medium Term Notes Due 2022 [Member]		
Debt Instrument [Line Items]		
Long-term debt	3,000,000	3,000,000
Year of debt maturity	2022	
Industrial Development And Environmental Improvement Bond [Member]		
Debt Instrument [Line Items]		
Long-term debt	0	198,000,000
Year of debt maturity	2013 - 2033	
Stated interest rate on long-term debt	4.75%	
Obligation Relating To Revenue Bonds Due 2013 [Member]		
Debt Instrument [Line Items]		
Long-term debt	23,000,000	23,000,000
Year of debt maturity	2013	
Stated interest rate on long-term debt	5.375%	
Obligation Relating To Revenue Bonds Due 2037 [Member]		
Debt Instrument [Line Items]		
Long-term debt	1,000,000,000	1,000,000,000
Year of debt maturity	2037	
Stated interest rate on long-term debt	5.125%	
Sale Leaseback Financing Due [Member]		
Debt Instrument [Line Items]		
Long-term debt	11,000,000	20,000,000
Year of debt maturity	2012	
Capital Lease Obligation Due 2012 [Member]		
Debt Instrument [Line Items]		
Long-term debt	9,000,000	17,000,000
Year of debt maturity	2012	
Consolidated Subsidiaries Secured Notes Due 2012 [Member]		
Debt Instrument [Line Items]		
Long-term debt	0	448,000,000
Year of debt maturity	2012	
Stated interest rate on long-term debt	8.375%	
Downstream Business Capital Lease Obligations Due 2034 [Member]		

Debt Instrument [Line Items]		
Long-term debt	0	279,000,000
Year of debt maturity	2012 - 2034	
Other capital lease obligations due 2012 - 2034		
Debt Instrument [Line Items]		
Long-term debt	$ 11,000,000	$ 12,000,000
Year of debt maturity	2012 - 2034	

Debt (Tables)

12 Months Ended Dec. 31, 2011

Debt Note Tables [Abstract]

Schedule of Extinguishment of Debt [Text Block]

(In millions)		
6.000% notes due 2012	$	400
6.125% notes due 2012		450
8.375% secured notes due 2012 [a]		448
6.500% debentures due 2014		700
5.900% notes due 2018		40
7.500% debentures due 2019		460
Total debt purchases	$	2,498

a) These notes were senior secured notes of Marathon Oil Canada Corporation.

Schedule of long term debt table [Text Block]

	December 31,			
(In millions)		2011		2010
Marathon Oil Corporation:				
Revolving credit facility	$	0	$	0
6.125% notes due 2012		0		450
6.000% notes due 2012		0		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		0		700
7.500% debentures due 2019 [a]		228		688
6.000% debentures due 2017 [a]		682		682
9.375% debentures due 2022		32		32
8.500% debentures due 2023		70		70
8.125% debentures due 2023		131		131
6.600% debentures due 2037		750		750
4.550% promissory note, semi-annual payments due 2012 - 2015		272		340
Series A medium term notes due 2022		3		3
4.750% - 6.875% obligations relating to industrial development and environmental improvement bonds and notes due 2013 - 2033		0		198
5.375% obligation relating to revenue bonds due 2013		23		23
5.125% obligation relating to revenue bonds due 2037		1,000		1,000
Sale-leaseback financing due 2012		11		20
Capital lease obligation due 2012		9		17
Consolidated subsidiaries				
8.375% secured notes due 2012 [a]		0		448
Capital lease obligations due 2012 - 2034				
Downstream business		0		279
Other		11		12
Total [b]		4,793		7,854

Unamortized fair value differential for debt assumed in acquisitions	0	16
Unamortized discount	(10)	(16)
Fair value adjustments {c}	32	42
Amounts due within one year	(141)	(295)
Total long-term debt due after one year	$ 4,674	$ 7,601

(a) These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

(b) In the event of a change in control, as defined in the related agreements, debt obligations totaling $431 million at December 31, 2011, may be declared immediately due and payable.

(c) See Note 15 for information on interest rate swaps

Five Year Schedule Of Debt Payments Table [Text Block]

(In millions)	
2012	$ 141
2013	205
2014	68
2015	68
2016	0

Spin-Off (Tables)	12 Months Ended Dec. 31, 2011

Spin Off Note Tables [Abstract]

Schedule Of Disposal Groups Including Discontinued Operations Balance Sheet Disclosures [Text Block]

(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

Spin Off Discontinued Operations Disclosure [Text Block]

(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

Debt (Details 1) (USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011	Dec. 31, 2010
Extinguishment of Debt [Line Items]		
Extinguishment of debt amount	$ 2,498	$ 500
Notes Due 2012 [A] [Member]		
Extinguishment of Debt [Line Items]		
Extinguishment of debt amount	400	
Maturity date of long-term debt	Jul. 01, 2012	
Stated interest rate for debt repurchases	6.00%	
Notes Due 2012 [B] [Member]		
Extinguishment of Debt [Line Items]		
Extinguishment of debt amount	450	
Maturity date of long-term debt	Mar. 15, 2012	
Stated interest rate for debt repurchases	6.13%	
Consolidated Subsidiaries Secured Notes Due 2012 [Member]		
Extinguishment of Debt [Line Items]		
Extinguishment of debt amount	448	
Maturity date of long-term debt	May 12, 2012	
Stated interest rate for debt repurchases	8.38%	
Debentures Due 2014 [Member]		
Extinguishment of Debt [Line Items]		
Extinguishment of debt amount	700	
Maturity date of long-term debt	Feb. 15, 2014	
Stated interest rate for debt repurchases	6.50%	
Notes Due 2018 [Member]		
Extinguishment of Debt [Line Items]		
Extinguishment of debt amount	40	
Maturity date of long-term debt	Mar. 15, 2018	
Stated interest rate for debt repurchases	5.90%	
Debentures Due 2019 [Member]		
Extinguishment of Debt [Line Items]		
Extinguishment of debt amount	$ 460	
Maturity date of long-term debt	Feb. 15, 2019	
Stated interest rate for debt repurchases	7.50%	

Fair Value Measurements (Details 2-Nonrecurring) (USD $) In Millions, unless otherwise specified	12 Months Ended				12 Months Ended	3 Months Ended
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009	Dec. 31, 2010 Assets Held for Sale Gudrun [Member]	Dec. 31, 2010 Assets Held and Used Powder River Basin [Member]	Jun. 30, 2011 Assets Held and Used Droshky [Member] Boe
Fair Value, Assets and Liabilities Measured on Nonrecurring Basis, Financial Statement [Line Items]						
Fair value of long-lived assets held for use, year-to-date	$ 226	$ 147	$ 5	$ 85	$ 144	$ 226
Impairment of long-lived assets held for use	282	447	15		423	273
Fair value of long-lived assets held for sale		85	311			
Impairment of long-lived assets held for sale		64	154			
Impairment of equity method investment		25				
Impairment of Intangible Assets, Finite-lived	$ 25					
Proved reserves write off						3.4

Stock-Based Compensation Plans (Details 2) (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Stock Options			
Beginning year stock option awards	24,912,261		
Granted stock option awards	7,676,544		
Exercised stock option awards	(3,576,373)		
Canceled stock option awards	(652,607)		
Downstream spin-off stock option award change	(6,989,110)		
End of year stock option awards	21,370,715	24,912,261	
Beginning year weighted average exercise price	$ 24.85		
Granted weighted average exercise price	$ 32.30	$ 30.00	$ 27.62
Exercises weighted average exercise price	$ 15.12		
Canceled weighted average exercise price	$ 25.88		
Downstream spin-off weighted average exercise price	$ 30.94		
End of year weighted average exercise price	$ 24.41	$ 24.85	
Intrinsic value of stock option awards exercised	$ 59	$ 8	$ 3

Income per Common Share (Details) (USD $) In Millions, except Per Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Earnings Per Share [Abstract]			
Income from continuing operations	$ 1,707	$ 1,882	$ 716
Discontinued operations	1,239	686	747
Net income	$ 2,946	$ 2,568	$ 1,463
Weighted average common shares outstanding, basic	710	710	709
Effect of dilutive securities	4	2	2
Weighted average common shares outstanding, diluted	714	712	711
Basic:			
Income from continuing operations, per basic share	$ 2.40	$ 2.65	$ 1.01
Discontinued operations, per basic share	$ 1.75	$ 0.97	$ 1.05
Net income, per basic share	$ 4.15	$ 3.62	$ 2.06
Diluted:			
Income from continuing operations, per diluted share	$ 2.39	$ 2.65	$ 1.01
Discontinued operations, per diluted share	$ 1.74	$ 0.96	$ 1.05
Net income, per diluted share	$ 4.13	$ 3.61	$ 2.06
Antidilutive securities excluded from computation of earnings per share	7	13	10

Derivatives (Details 2-IS & OCI) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income	$ 5	$ 121	$ 93
Foreign currency [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Derivative Instruments, Gain (Loss) Recognized in Other Comprehensive Income (Loss), Effective Portion, Net		4	39
Interest rate [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Derivative Instruments, Gain (Loss) Recognized in Other Comprehensive Income (Loss), Effective Portion, Net			(15)
Fair Value Hedges [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income	28	25	(16)
Change in unrealized gain (loss) on hedged item in fair value hedge	(28)	(25)	16
Sales [Member] | Commodity [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income	5	121	90
Sales [Member] | Fair Value Hedges [Member] | Commodity [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income		(1)	(16)
Change in unrealized gain (loss) on hedged item in fair value hedge		1	16
Net Interest and other Financing Costs [Member] | Foreign currency [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income			3
Net Interest and other Financing Costs [Member] | Fair Value Hedges [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Change in unrealized gain (loss) on hedged item in fair value hedge	(28)	(26)	
Net Interest and other Financing Costs [Member] | Fair Value Hedges [Member] | Interest rate [Member]			
Gain (Loss) on Derivative Instruments [Line Items]			
Gain (loss) on derivative instruments recognized in income	$ 28	$ 26	

Defined Benefit Postretirement Plans (Details 5) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Defined Benefit Plan Disclosure [Line Items]			
Defined Benefit Plan, Fair Value of Plan Assets	$ 6		
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]			
Spin-off downstream businesses	2		
Purchases		2	5
Sales			(23)
Settlements		(10)	30
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset Value, Ending Balance	23		
Sale of investment that did not cash settle	18		
United States Pension Plans Of US Entity Defined Benefit [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Defined Benefit Plan, Fair Value of Plan Assets	516	1,798	1,623
Foreign Pension Plans Defined Benefit [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Defined Benefit Plan, Fair Value of Plan Assets	412	389	348
Fair Value, Inputs, Level 1 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Cash And Cash Equivalents [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Defined Benefit Plan, Fair Value of Plan Assets	12	8	
Fair Value, Inputs, Level 1 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Equity Securities Investment Objective [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Defined Benefit Plan, Fair Value of Plan Assets		25	
Fair Value, Inputs, Level 1 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Exchange Traded Funds [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Defined Benefit Plan, Fair Value of Plan Assets		56	
Fair Value, Inputs, Level 1 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | US Treasury [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Defined Benefit Plan, Fair Value of Plan Assets	92		
Fair Value, Inputs, Level 1 [Member] | Foreign Pension Plans Defined Benefit [Member] | Cash And Cash Equivalents [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Defined Benefit Plan, Fair Value of Plan Assets	2	1	
Fair Value, Inputs, Level 1 [Member] | Foreign Pension Plans Defined Benefit [Member] | Investment Funds Mutual Funds Equity [Member]			
Defined Benefit Plan Disclosure [Line Items]			

Defined Benefit Plan, Fair Value of Plan Assets	159	161
Fair Value Inputs Level 2 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Equity Securities Investment Objective [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets	7	137
Fair Value Inputs Level 2 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Equity Funds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets		1,072
Fair Value Inputs Level 2 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Fixed Income Funds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets		350
Fair Value Inputs Level 2 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Other Investments [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets	30	5
Fair Value Inputs Level 2 [Member] | Foreign Pension Plans Defined Benefit [Member] | Equity Funds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets	96	97
Fair Value Inputs Level 2 [Member] | Foreign Pension Plans Defined Benefit [Member] | Fixed Income Funds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets	149	126
Fair Value Inputs Level 2 [Member] | Foreign Pension Plans Defined Benefit [Member] | Other Investments [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets		4
Fair Value, Inputs, Level 3 [Member] | Private Equity Funds [Member]		
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]		
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset Value, Beginning Balance	67	42
Spin-off downstream businesses	(46)	
Actual Return on plan assets	3	13
Purchases	3	15
Sales	(4)	(3)
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset Value, Ending Balance		67
Fair Value, Inputs, Level 3 [Member] | Real Estate [Member]		
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]		
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset Value, Beginning Balance	54	36
Spin-off downstream businesses	(37)	
Actual Return on plan assets	2	4

Purchases	4	17
Sales	(2)	(3)
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset Value, Ending Balance	21	54
Fair Value, Inputs, Level 3 [Member] | Other Investments [Member]		
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]		
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset Value, Beginning Balance	24	23
Spin-off downstream businesses	(17)	
Actual Return on plan assets		1
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset Value, Ending Balance	7	24
Fair Value, Inputs, Level 3 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Exchange Traded Funds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets	324	
Fair Value, Inputs, Level 3 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Private Equity Funds [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets	23	67
Fair Value, Inputs, Level 3 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Real Estate [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets	21	54
Fair Value, Inputs, Level 3 [Member] | United States Pension Plans Of US Entity Defined Benefit [Member] | Other Investments [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Defined Benefit Plan, Fair Value of Plan Assets	$ 7	$ 24

Supplemental Cash Flow Information (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Net cash provided by continuing operatons:			
Interest paid (net of amounts capitalized)	$ 268	$ 107	$ 19
Income taxes paid to taxing authorities	2,893	2,155	1,663
Commercial paper and revolving credit arrangements, net:			
Commercial paper - issuances	421	0	897
Commercial paper - repayments	421	0	897
Noncash investing and financing activities			
Asset retirement costs capitalized, excluding acquisitions	151	207	135
Change In Capital Accruals	104	(140)	(28)
Debt payments made on our behalf	214	105	144
Capital lease obligations increase			$ 9

Defined Benefit Postretirement Plans (Details 6) (USD $) In Millions, unless otherwise specified	12 Months Ended			
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Defined Benefit Plan Information About Plan Assets [Abstract]				
Contributions to defined benefit plan	$ 113			
Cash Contributions Expected To Be Paid From General Assets Postretirement Plan		21		
Cash Contributions Expected To Be Paid From General Assets Unfunded Plan		18		
Medicare reimbursement		5		
Prescription drug subsidy no longer tax deductible		22		
Defined contribution plan contributions		50	75	59
Defined Benefit Plan Target Allocation Percentage Of Assets Debt Securities	35.00%	25.00%		
Defined Benefit Plan Target Allocation Percentage Of Assets Equity Securities	65.00%	75.00%		
Defined Benefit International Plan, Target Allocation Percentage of Assets, Debt Securities		30.00%		
Defined Benefit International Plan, Target Allocation Percentage of Assets, Equity Securities		70.00%		
Other Postretirement Benefit Plans Defined Benefit [Member]				
Defined Benefit Plan Estimated Future Benefit Payments [Line Items]				
Expected Future Benefit Payments In Year One		21		
Expected Future Benefit Payments In Year Two		22		
Expected Future Benefit Payments In Year Three		22		
Expected Future Benefit Payments In Year Four		23		
Expected Future Benefit Payments In Year Five		24		
Expected Future Benefit Payments Five Years Thereafter		121		
United States Pension Plans Of US Entity Defined Benefit [Member]				
Defined Benefit Plan Estimated Future Benefit Payments [Line Items]				
Expected Future Benefit Payments In Year One		104		
Expected Future Benefit Payments In Year Two		100		
Expected Future Benefit Payments In Year Three		102		
Expected Future Benefit Payments In Year Four		101		
Expected Future Benefit Payments In Year Five		104		
Expected Future Benefit Payments Five Years Thereafter		482		
Foreign Pension Plans Defined Benefit [Member]				
Defined Benefit Plan Estimated Future Benefit Payments [Line Items]				
Expected Future Benefit Payments In Year One		12		
Expected Future Benefit Payments In Year Two		13		

Expected Future Benefit Payments In Year Three	15
Expected Future Benefit Payments In Year Four	16
Expected Future Benefit Payments In Year Five	18
Expected Future Benefit Payments Five Years Thereafter	$ 105

Derivatives (Details 3) (USD $) In Millions, unless otherwise specified	12 Months Ended	
	Dec. 31, 2011	Dec. 31, 2010
Interest Rate Fair Value Hedges [Abstract]		
Notional Amount of Interest Rate Fair Value Hedge Derivatives	$ 600	$ 1,450
Weighted-average, LIBOR-based, floating rate	4.76%	4.43%
Interest Rate Swaps	$ 29	

Goodwill (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Goodwill [Line Items]			
Goodwill Gross		$ 2,792	$ 2,834
Goodwill, Impaired, Accumulated Impairment Loss		(1,412)	(1,412)
Goodwill Roll Forward			
Beginning Balance	1,380	1,422	
Contingent consideration adjustment	(3)	(1)	
Goodwill Spinoff Transaction	(847)		
Goodwill Translation And Purchase Accounting Adjustments	9	(7)	
Goodwill Written Off Related To Sale Of Business Unit	(3)	(34)	
Ending Balance	536	1,380	
Exploration and Production Segment [Member]			
Goodwill [Line Items]			
Goodwill Gross		537	537
Goodwill Roll Forward			
Beginning Balance	537		537
Goodwill Written Off Related To Sale Of Business Unit	(1)		
Ending Balance	536		537
Oil Sands Mining Segment [Member]			
Goodwill [Line Items]			
Goodwill Gross		1,412	1,412
Goodwill, Impaired, Accumulated Impairment Loss		(1,412)	(1,412)
Goodwill Roll Forward			
Ending Balance	0	0	
Refining, Marketing and Transportation Segment [Member]			
Goodwill [Line Items]			
Goodwill Gross		843	885
Goodwill Roll Forward			
Beginning Balance	843	885	
Contingent consideration adjustment	(3)	(1)	
Goodwill Spinoff Transaction	(847)		
Goodwill Translation And Purchase Accounting Adjustments	9	(7)	
Goodwill Written Off Related To Sale Of Business Unit	(2)	(34)	
Ending Balance	$ 0	$ 843	

Asset Retirement Obligations	12 Months Ended Dec. 31, 2011
Asset Retirement Obligations Disclosure [Abstract]	
Asset Retirement Obligations	

18. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)	2011	2010
Beginning balance	$ 1,355	$ 1,102
Incurred, including acquisitions	37	49
Settled	(39)	(28)
Accretion expense (included in depreciation, depletion and amortization)	81	70
Revisions to previous estimates	126	162
Spin-off downstream business	(50)	-
Ending balance[a]	$ 1,510	$ 1,355

a. Includes asset retirement obligation of $1 million classified as short-term at December 31, 2010.

Stock-Based Compensation Plans (Tables)

12 Months Ended Dec. 31, 2011

Stock Based Compensation Plans Note Tables [Abstract]

Share-based Compensation Arrangement by Share-based Payment Award, Options, Grants in Period, Weighted Average Grant Date Fair Value [Table Text Block]

	2011	2010	2009
Weighted average exercise price per share	$ 32.30	$ 30.00	$ 27.62
Expected annual dividend yield	2.1%	3.2%	3.5%
Expected life in years	5.3	5.1	4.9
Expected volatility	40%	43%	41%
Risk-free interest rate	1.7%	2.2%	2.3%
Weighted average grant date fair value of stock option awards granted	$ 10.44	$ 8.70	$ 7.67

Schedule of Share-based Compensation, Stock Options, Activity [Table Text Block]

	Number of Shares	Weighted Average Exercise price
Outstanding at beginning of year	24,912,261	$ 24.85
Granted	7,676,544	32.30
Exercised	(3,576,373)	15.12
Cancelled	(652,607)	25.88
Spin-off downstream business	(6,989,110)	30.94
Outstanding at end of year	21,370,715	$ 24.41

Schedule of Share-based Compensation, Shares Authorized under Stock Option Plans, by Exercise Price Range [Table Text Block]

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Under Option	Weighted Average Exercise Price
$ 7.99-12.75	1,272,745	2	$ 10.23	1,272,745	$ 10.23
12.76-16.81	2,850,590	5	15.21	2,354,373	15.28
16.82-23.20	6,642,268	8	18.60	2,810,120	18.52
23.21-29.24	2,021,400	4	23.92	1,955,767	23.82
29.25-30.36	22,388	7	29.56	22,388	29.56
30.37-47.91	8,561,324	7	34.20	4,690,067	35.75
Total	21,370,715	6	24.41	13,105,460	24.11

Schedule of Nonvested Restricted Stock Units Activity [Table Text Block]

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	2,084,680	$ 23.03
Granted	3,066,978 {a}	27.74
Vested	(993,949)	27.34
Forfeited	(163,806)	23.88
Spin-off downstream business	(289,925)	21.30
Unvested at end of year	3,703,978	25.88

Property, Plant and Equipment (Tables)	12 Months Ended Dec. 31, 2011
Property Plant And Equipment Note Tables [Abstract]	
Schedule of Aging of Capitalized Exploratory Well Costs [Table Text Block]	(see table below)

(In millions)	December 31, 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

Capitalized Exploratory Well Costs, Roll Forward [Table Text Block]

(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

Schedule of Projects with Exploratory Well Costs Capitalized for More than One Year [Table Text Block]

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

Schedule Of Property Plant And Equipment [Table Text Block]

(In millions)	December 31, 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

Derivatives (Details-BS) (USD $) In Millions, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Derivatives Fair Value [Line Items]		
Derivative Asset, Fair Value, Gross Asset	$ 5	$ 90
Derivative Asset, Fair Value, Gross Liability		102
Derivative Asset, Fair Value, Net	5	(12)
Derivative Liability, Fair Value, Gross Asset		1
Derivative Liability, Fair Value, Gross Liability		3
Derivative Liability, Fair Value, Net		2
Designated as Hedging Instrument [Member]		
Derivatives Fair Value [Line Items]		
Derivative Asset, Fair Value, Gross Asset	5	32
Derivative Asset, Fair Value, Net	5	32
Not Designated as Hedges [Member]		
Derivatives Fair Value [Line Items]		
Derivative Asset, Fair Value, Gross Asset		58
Derivative Asset, Fair Value, Gross Liability		102
Derivative Asset, Fair Value, Net		(44)
Derivative Liability, Fair Value, Gross Asset		1
Derivative Liability, Fair Value, Gross Liability		3
Derivative Liability, Fair Value, Net		2
Commodity [Member] | Other Current Assets [Member] | Not Designated as Hedges [Member]		
Derivatives Fair Value [Line Items]		
Derivative Asset, Fair Value, Gross Asset		58
Derivative Asset, Fair Value, Gross Liability		102
Derivative Asset, Fair Value, Net		(44)
Commodity [Member] | Other Current Liabilities [Member] | Not Designated as Hedges [Member]		
Derivatives Fair Value [Line Items]		
Derivative Liability, Fair Value, Gross Asset		1
Derivative Liability, Fair Value, Gross Liability		3
Derivative Liability, Fair Value, Net		2
Interest rate [Member] | Other Noncurrent Assets [Member] | Designated as Hedging Instrument [Member]		
Derivatives Fair Value [Line Items]		
Derivative Asset, Fair Value, Gross Asset	5	32
Derivative Asset, Fair Value, Net	$ 5	$ 32

Segment Information (Tables)	12 Months Ended Dec. 31, 2011
Segment Information Note Tables [Abstract]	
Schedule of Segment Reporting Information, by Segment [Table Text Block]	

(In millions)	E&P	OSM	IG	Total
2011				
Revenues:				
Customer	$ 12,922	$ 1,588	$ 93	$ 14,603
Intersegment	47	0	0	47
Related parties	60	0	0	60
Segment revenues	13,029	1,588	93	14,710
Elimination of intersegment revenues	(47)	0	0	(47)
Total revenues	$ 12,982	$ 1,588	$ 93	$ 14,663
Segment income	$ 2,157	$ 256	$ 178	$ 2,591
Income from equity method investments	249	0	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	0	0	75
Related parties	56	0	0	56
Segment revenues	10,782	833	150	11,765
Elimination of intersegment revenues	(75)	0	0	(75)
Total revenues	$ 10,707	$ 833	$ 150	$ 11,690
Segment income (loss)	$ 1,941	$ (50)	$ 142	$ 2,033
Income from equity method investments	188	0	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	0	0	28
Related parties	59	0	0	59
Segment revenues	7,738	692	50	8,480
Elimination of intersegment revenues	(28)	0	0	(28)
Gain on U.K. natural gas contracts {a}	72	0	0	72 {a}
Total revenues	$ 7,782	$ 692	$ 50	$ 8,524

Segment income	$ 1,218	$ 44	$ 90	$ 1,352
Income from equity method investments	125	0	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.

Reconciliation of segment income to net 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)	0
Tax effect of subsidiary restructuring	(122)	0	0
Deferred income taxes	(61)	(45)	0
Water abatement - Oil Sands	(48)	0	0
Eagle Ford transaction costs	(10)	0	0
Gain on dispositions [b]	45	407	122
Gain on U.K. natural gas contracts	0	0	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.

Reconciliation of Revenue from Segments to Consolidated [Table Text Block]

(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 customers 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

Long-lived assets by geographic area

(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

Revenues by product line

(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

Spin-Off (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended			
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009	Jun. 30, 2011
Current assets of discontinued operations:				
Cash and cash equivalents of discontinued operations				$ 1,622
Receivables of discontinued operations				5,041
Inventories of discontinued opeartions				3,679
Other current assets of discontinued operations				170
Total current assets of discontinued operations				10,512
Noncurrent assets of discontinued operations [Abstract]				
Equity method investments of discontinued operations				323
Property, plant, and equipment of discontinued operations				11,935
Goodwill of discontinued operations				847
Other noncurrent assets of discontinued operations				351
Total assets of discontinued operations				23,968
Current liabilities of discontinued operations:				
Accounts payable of discontinued operations				7,329
Payroll and benefits payable of discontinued operations				222
Accrued and deferred taxes of discontinued operations				443
Other current liabilities of discontinued operations				461
Long term debt of discontinued operations, due within one year				12
Total current liabilities of discontinued operations				8,467
Long term debt of discontinued operations				3,262
Deferred income taxes of discontinued operations				1,568
Defined benefit postretirement plan obligations of discontinued operations				1,489
Deferred credits and other noncurrent liabilities of discontinued operations				276
Total liabilities of discontinued operations				15,062
Discontinued Operations Disclosure [Abstract]				
Revenues applicable to discontinued operations	38,602	62,488	45,529	
Pretax income from discontinued operations	$ 2,012	$ 1,065	$ 894	

EMI and Related Party (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Schedule Of Equity Method Investments [Line Items]			
Carrying value of equity method investments	$ 1,383	$ 1,802	
Income Data- Year			
Equity method investment revenues and other income	1,544	2,243	1,916
Equity method investment income from operations	942	999	677
Net Income	820	841	576
Balance sheet data			
Current Assets	688	898	
Noncurrent Assets	2,079	3,371	
Current Liabilities	504	513	
Noncurrent Liabilities	115	832	
Equity Method Investment Difference Between Carrying Amount And Underlying Equity	155		
Dividends and partnership distributions received from equity method investments	509	400	302
EG Holdings [Member]			
Schedule Of Equity Method Investments [Line Items]			
Carrying value of equity method investments	875	927	
Ownership percentage	60.00%		
Alba Plant LLC [Member]			
Schedule Of Equity Method Investments [Line Items]			
Carrying value of equity method investments	272	303	
Ownership percentage	52.00%		
AMPCO [Member]			
Schedule Of Equity Method Investments [Line Items]			
Carrying value of equity method investments	191	210	
Ownership percentage	45.00%		
Other Equity Method Investees [Member]			
Schedule Of Equity Method Investments [Line Items]			
Carrying value of equity method investments	45	51	
Downstream business investments [Member]			
Schedule Of Equity Method Investments [Line Items]			
Carrying value of equity method investments		$ 311	

Segment Information (Details 4) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Revenue from External Customer [Line Items]			
Revenuse by product line	$ 14,663	$ 11,690	$ 8,524
Liquid hydrocarbons [Member]			
Revenue from External Customer [Line Items]			
Revenuse by product line	13,298	10,312	7,343
Natural Gas [Member]			
Revenue from External Customer [Line Items]			
Revenuse by product line	1,291	1,295	1,126
Transportation and other [Member]			
Revenue from External Customer [Line Items]			
Revenuse by product line	$ 74	$ 83	$ 55

Asset Retirement Obligations (Tables)

12 Months Ended Dec. 31, 2011

Asset Retirement Obligation Disclosure [Abstract]

Schedule of Change in Asset Retirement Obligation [Table Text Block]

(In millions)	2011	2010
Beginning balance	$ 1,355	$ 1,102
Incurred, including acquisitions	37	49
Settled	(39)	(28)
Accretion expense (included in depreciation, depletion and amortization)	81	70
Revisions to previous estimates	126	162
Spin-off downstream business	(50)	-
Ending balance [a]	$ 1,510	$ 1,355

a. Includes asset retirement obligation of $1 million classified as short-term at December 31, 2010.

a. Includes asset retirement obligation of $1 million classified as short-term at December 31, 2010.

Accounting Standards	12 Months Ended Dec. 31, 2011
Accounting Standards Disclosure [Abstract]	
Accounting Standards	

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.

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.

Other Items (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Net Interest and Other Financing [Abstract]			
Interest income	$ 12	$ 11	$ 8
Interest expense	(281)	(375)	(262)
Income(loss) on interest rate swaps	10	26	17
Interest capitalized	151	297	214
Net interest	(108)	(41)	(23)
Net foreign currency gains or losses	24	(21)	(28)
Write off contigent proceeds	(7)	(15)	(70)
Other	(16)	2	(1)
Total other	1	(34)	(99)
Net interest and other financing costs	(107)	(75)	(122)
Interest payments made on our behalf	10	16	27
Aggregate foreign currency gains losses [Abstract]			
Net foreign currency gains or losses	24	(21)	(28)
Provision for income taxes foreign currency transaction gain loss	(57)	(1)	(319)
Aggregate foreign currency gains (losses)	$ (33)	$ (22)	$ (347)

Goodwill (Tables)

12 Months Ended Dec. 31, 2011

Goodwill Rollforward Table [Abstract]

Schedule of Goodwill [Table Text Block]

(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

Stockholders' Equity	12 Months Ended Dec. 31, 2011
Stockholders Equity Disclosure [Abstract]	
Stockholders' Equity	

22. Stockholders' Equity

Securities exchangeable into Marathon common stock – In conjunction with our acquisition of Western Oil Sands Inc. ("Western") on October 18, 2007, Canadian residents were able to receive, at their election, cash, Marathon common stock or securities exchangeable into Marathon common stock (the "Exchangeable Shares"). The Exchangeable Shares were shares of an indirect Canadian subsidiary of Marathon and were exchanged into Marathon stock based upon an exchange ratio that began at one-for-one and adjusted quarterly to reflect cash dividends. The Exchangeable Shares were exchangeable at the option of the holder at any time and were automatically redeemable on October 18, 2011. They could also be redeemed prior to their automatic redemption if certain conditions were met. Those conditions were met and we filed notice of the proposed redemption in Canada on March 3, 2010. On April 7, 2010, the remaining exchangeable shares were redeemed.

Preferred shares – Also in connection with our acquisition of Western, the Board of Directors authorized a class of voting preferred stock. Upon completion of the acquisition, we issued shares of this voting preferred stock to a trustee, who held the shares for the benefit of the holders of the Exchangeable Shares discussed above. Each share of voting preferred stock was entitled to one vote on all matters submitted to the holders of Marathon common stock. Each holder of Exchangeable Shares could direct the trustee to vote the number of shares of voting preferred stock equal to the number of shares of Marathon common stock issuable upon the exchange of the Exchangeable Shares held by that holder. In no event would the aggregate number of votes entitled to be cast by the trustee with respect to the outstanding shares of voting preferred stock exceed the number of votes entitled to be cast with respect to the outstanding Exchangeable Shares. Except as otherwise provided in our restated certificate of incorporation or by applicable law, the common stock and the voting preferred stock voted together as a single class in the election of directors of Marathon and on all other matters submitted to a vote of stockholders of Marathon generally. The voting preferred stock had no other voting rights except as required by law. Other than dividends payable solely in shares of voting preferred stock, no dividend or other distribution, was paid or payable to the holder of the voting preferred stock. In the event of any liquidation, dissolution or winding up of Marathon, the holder of shares of the voting preferred stock would not be entitled to receive any assets of Marathon available for distribution to its stockholders. The voting preferred stock was not convertible into any other class or series of the capital stock of Marathon or into cash, property or other rights, and could not be redeemed. In connection with the redemption of the Exchangeable Shares, these preferred shares were eliminated in June 2010.

Share repurchase plan – The Board of Directors has authorized the repurchase of up to $5 billion of our common stock. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables. As of December 31, 2011, we had acquired 78 million common shares at a cost of $3,222 million under this authorized share repurchase program, including 12 million common shares acquired during 2011 at a cost of $300 million.

Incentive Based Compensation	12 Months Ended Dec. 31, 2011
Stock Based Compensation Plans Disclosure [Abstract]	
Stock-Based Compensation Plans	

21. Incentive Based Compensation

Description of Stock Based Compensation Plans

The Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") was approved by our stockholders in April 2007 and authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights, stock awards (including restricted stock and restricted stock unit awards) and performance awards to employees. The 2007 Plan also allows us to provide equity compensation to our non-employee directors. No more than 34 million shares of our common stock may be issued under the 2007 Plan and no more than 12 million of those shares may be used for awards other than stock options or stock appreciation rights.

Shares subject to awards under the 2007 Plan that are forfeited, are terminated or expire unexercised become available for future grants. If a stock appreciation right is settled upon exercise by delivery of shares of common stock, the full number of shares with respect to which the stock appreciation right was exercised will count against the number of shares of our common stock reserved for issuance under the 2007 Plan and will not again become available under the 2007 Plan. In addition, the number of shares of our common stock reserved for issuance under the 2007 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2007 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2007 Plan, no new grants were or will be made from the 2003 Incentive Compensation Plan (the "2003 Plan"). The 2003 Plan replaced the 1990 Stock Plan, the Non-Officer Restricted Stock Plan, the Non-Employee Director Stock Plan, the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors, the Senior Executive Officer Annual Incentive Compensation Plan and the Annual Incentive Compensation Plan (the "Prior Plans"). No new grants will be made from the Prior Plans. Any awards previously granted under the 2003 Plan or the Prior Plans shall continue to be exercisable in accordance with their original terms and conditions.

Stock based awards under the Plan

Stock options – We grant stock options under the 2007 Plan. Our stock options represent the right to purchase shares of our common stock at its fair market value on the date of grant. Through 2004, certain stock options were granted under the 2003 Plan with a tandem stock appreciation right, which allows the recipient to instead elect to receive cash or our common stock equal to the excess of the fair market value of shares of common stock, as determined in accordance with the 2003 Plan, over the option price of the shares. In general, stock options granted under the 2007 Plan and the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock appreciation rights – Prior to 2005, we granted SARs under the 2003 Plan. No stock appreciation rights have been granted under the 2007 Plan. Similar to stock options, stock appreciation rights represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. Under the 2003 Plan, certain SARs were granted as stock-settled SARs and others were granted in tandem with stock options. In general, SARs granted under the 2003 Plan vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Restricted stock – We grant restricted stock and restricted stock units under the 2007 Plan and previously granted such awards under the 2003 Plan. In 2005, the Compensation Committee began granting time-based restricted stock to certain of our U.S.-based officers as part of their annual long-term incentive package. The restricted stock awards to officers vest three years from the date of grant, contingent on the recipient's continued employment. We also grant restricted stock to certain non-officer employees and restricted stock units to certain international employees ("restricted stock awards"), based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest in one-third increments over a three-year period, contingent on the recipient's continued employment, however, certain restricted stock awards will vest over a four-year period, contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by our transfer agent.

Common stock units – We maintain an equity compensation program for our non-employee directors under the 2007 Plan and previously maintained such a program under the 2003 Plan. All non-employee directors receive annual grants of common stock units, and they are required to hold units granted prior to 2012 until they leave the Board of Directors. When dividends are paid on our common stock, directors receive dividend equivalents in the form of additional common stock units.

Total stock based compensation expense

Total employee stock based compensation expense related to continuing operations was $65 million, $51 million and $59 million in 2011, 2010 and 2009, while the total related income tax benefits were $23 million, $19 million and $22 million in the same years. In 2011, 2010 and 2009 cash received upon exercise of stock option awards related was $77 million, $12 million and $4 million. Tax benefits realized for deductions for stock awards exercised during 2011, 2010 and 2009 totalled $32 million, $11 million and $10 million.

Stock option awards

During 2011, 2010 and 2009, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following Black-Scholes assumptions:

	2011	2010	2009
Weighted average exercise price per share	$ 32.30	$ 30.00	$ 27.62
Expected annual dividend yield	2.1%	3.2%	3.5%
Expected life in years	5.3	5.1	4.9
Expected volatility	40%	43%	41%
Risk-free interest rate	1.7%	2.2%	2.3%
Weighted average grant date fair value of stock option awards granted	$ 10.44	$ 8.70	$ 7.67

The following is a summary of stock option award activity in 2011.

	Number of Shares	Weighted Average Exercise price
Outstanding at beginning of year	24,912,261	$ 24.85
Granted	7,676,544	32.30
Exercised	(3,576,373)	15.12
Cancelled	(652,607)	25.88
Spin-off downstream business	(6,989,110)	30.94
Outstanding at end of year	21,370,715	$ 24.41

The intrinsic value of stock option awards exercised during 2011, 2010 and 2009 was $59 million, $8 million and $3 million.

The following table presents information related to stock option awards at December 31, 2011.

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Under Option	Weighted Average Exercise Price
$ 7.99-12.75	1,272,745	2	$ 10.23	1,272,745	$ 10.23
12.76-16.81	2,850,590	5	15.21	2,354,373	15.28
16.82-23.20	6,642,268	8	18.60	2,810,120	18.52
23.21-29.24	2,021,400	4	23.92	1,955,767	23.82
29.25-30.36	22,388	7	29.56	22,388	29.56
30.37-47.91	8,561,324	7	34.20	4,690,067	35.75
Total	21,370,715	6	24.41	13,105,460	24.11

As of December 31, 2011, the aggregate intrinsic value of stock option awards outstanding was $146 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable were $98 million and 5 years.

As of December 31, 2011, the number of fully-vested stock option awards and stock option awards expected to vest was 21,142,660. The weighted average exercise price and weighted average remaining contractual life of these stock option awards were $24.38 and 6 years and the aggregate intrinsic value was $145 million. As of December 31, 2011, unrecognized compensation cost related to stock option awards was $36 million, which is expected to be recognized over a weighted average period of 2 years.

Restricted stock awards

The following is a summary of restricted stock award activity

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	2,084,680	$ 23.03
Granted	3,066,978 {a}	27.74
Vested	(993,949)	27.34
Forfeited	(163,806)	23.88
Spin-off downstream business	(289,925)	21.30

Unvested at end of year	3,703,978	25.88

(a) Beginning in August, 2011, most employees on the U.S., U.K., Canadian and Norwegian payrolls are eligible for a restricted stock grant, based on performance.

The vesting date fair value of restricted stock awards which vested during 2011, 2010 and 2009 was $30 million, $21 million and $24 million. The weighted average grant date fair value of restricted stock awards was $25.88, $23.03, and $44.89 for awards unvested at December 31, 2011, 2010 and 2009.

As of December 31, 2011, there was $78 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of 2.5 years.

Performance unit awards

Performance units provide for named executive officers to receive a cash payment upon the achievement of certain performance goals at the end of a defined measurement period. The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. The target value of each performance unit is $1, with the actual payout varying from $0 to $2 per unit (capped at a maximum payout of $2 per unit). Because performance units are to be settled in cash at the end of the performance period, they are accounted for as liability awards. Compensation expense related to continuing operations associated with performance units was $32 million and $2 million in 2011 and 2009, but was not significant in 2010. Expense for 2011 included $14 million paid on three groups of performance unit grants outstanding June 30, 2011, that were accelerated with the total payout determined based on performance through the effective date of the spin-off of our downstream business.

During the third quarter of 2011, we granted 15 million performance units to named executive officers. A portion of these units have an 18-month performance period and a portion have a 30-month performance period to reflect the remaining periods of the original 2011 and 2010 performance unit grants outstanding prior to the spinoff.

Dispositions (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended								12 Months Ended		12 Months Ended	12 Months Ended								
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009	Dec. 31, 2009 Ireland and Gabon [Member]	Dec. 31, 2012 GOM Pipelines [Member]	Dec. 31, 2011 Burnspoint [Member]	Dec. 31, 2011 Burnspoint [Member] Disposed [Member]	Dec. 31, 2011 Alaska Lng [Member]	Dec. 31, 2011 DJ Basin [Member] acres	Dec. 31, 2011 DJ Basin [Member] Disposed [Member]	Dec. 31, 2010 Angola [Member]	Dec. 31, 2010 Angola [Member] Disposed [Member]	Dec. 31, 2010 Angola [Member] Held [Member]	Dec. 31, 2010 Gudrun [Member]	Dec. 31, 2009 Gabon [Member]	Dec. 31, 2009 Permian Basin [Member]	Dec. 31, 2009 Ireland (Operated Properties) [Member]	Dec. 31, 2011 Ireland (Corrib) [Member]	Dec. 31, 2009 Ireland (Corrib) [Member]	Dec. 31, 2009 Ireland (Corrib) [Member] Disposed [Member]
Dispositions Detail [Line Items]																				
Equity method investments	$ 1,383	$ 1,802			$ 38															
Proceeds from Sale of Oil and Gas Property and Equipment	518	1,368	812		205	36			270		1,300			85	269	293	84			
Pretax gain/loss on sale						34		8	37		811			(64)	232	196	158			
Charge for pension plan termination																	18			
Impairment of long-lived assets held for sale		64	154																154	
Interest Percentage							50.00%			30.00%		20.00%	10.00%							19.00%
Gas and oil acreages, net									180,000											
Initial proceeds payment dispositon of asset																		100		
Fixed proceeds on disposition of asset																			135	
Pretax income and revenue discontinued operation [Line Items]																				
Revenues applicable to discontinued operations	38,602	62,488	45,529	188																
Pretax income from discontinued operations	$ 2,012	$ 1,065	$ 894	$ 80																

Fair Value (Tables)

12 Months Ended Dec. 31, 2011

Fair Value Measurements Note Tables [Abstract]

Derivative Fair Value Assets And Liabilities Table [Text Block]

(In millions)	December 31, 2010 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)

Nonrecurring fair value table

(In millions)	2011 Fair Value	2011 Impairment	2010 Fair Value	2010 Impairment	2009 Fair Value	2009 Impairment
Long-lived assets held for use	$ 226	$ 282	$ 147	$ 447	$ 5	$ 15
Long-lived assets held for sale	0	0	85	64	311	154
Intangible assets	0	25	0	0	0	0
Equity method investments	0	0	0	25	0	0

Financial instruments fair value table

(In millions)	December 31, 2011 [a] Fair Value	2011 [a] Carrying Amount	2010 Fair Value	2010 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.

Fair value recurring derivative level 3 rollforward [Table Text Block]

(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

Leases	12 Months Ended Dec. 31, 2011
Leases Of Lessee Disclosure [Abstract]	
Leases of Lessee Disclosure [Text Block]	**23. Leases**

23. Leases

We lease a wide variety of facilities and equipment under operating leases, including land, building space, equipment and vehicles. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations (including sale-leasebacks accounted for as financings) and for operating lease obligations having initial or remaining noncancelable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2012	$ 22	$ 42
2013	1	38
2014	1	29
2015	1	26
2016	1	25
Later years	25	66
Sublease rentals	0	(2)
Total minimum lease payments	$ 51	$ 224
Less imputed interest costs	(20)	
Present value of net minimum lease payments	$ 31	

Operating lease rental expense related to continuing operations was $74 million, $77 million and $105 million in 2011, 2010 and 2009, which excludes $16 million and $3 million paid by United States Steel on assumed leases in 2010 and 2009.

Commitments and Contingencies	12 Months Ended Dec. 31, 2011
Commitments And Contingencies [Abstract]	
Commitments and Contingencies	

24. Commitments and Contingencies

We are a 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 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 matters – We are subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

At December 31, 2011 and 2010, accrued liabilities for remediation totaled $1 million and $119 million. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed.

Guarantees **–** We have provided certain guarantees, direct and indirect, of the indebtedness of other companies. Under the terms of most of these guarantee arrangements, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements. In addition to these financial guarantees, we also have various performance guarantees related to specific agreements.

United States Steel was the sole general partner of Clairton 1314B Partnership, L.P., which owned certain facilities formerly owned by United States Steel. We have agreed, under certain circumstances, to indemnify the limited partners if the partnership's product sales fail to qualify for the credit under Section 29 of the Internal Revenue Code. The Clairton 1314B Partnership was terminated on October 31, 2008, but we were not released from our obligations. United States Steel has estimated the maximum potential amount of this indemnity obligation, including interest and tax gross-up, was approximately $110 million as of December 31, 2011, all of which is related to our continuing operations.

We have entered into other guarantees related to our continuing operations with maximum potential undiscounted payments totaling $139 million as of December 31, 2011, which consist primarily of leases of corporate assets containing general lease indemnities and guaranteed residual values, a performance guarantee and a long-term transportation services agreement.

In October 2010, upon acquiring a position in four exploration blocks in the Iraqi Kurdistan Region, we indemnified the KRG against any negative tax effects related to certain payments we are obligated to make to the KRG. As of December 31, 2011, some of those payments had been made, no related taxes have been assessed, and neither is there any history of such payments being taxed. Given the lack of history of tax assessment against such payments, and because certain of our future payments to the KRG are not quantifiable, a maximum potential undiscounted payments cannot be calculated.

Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

***Contract commitments* –** At December 31, 2011 and 2010, contractual commitments of our continuing operations to acquire property, plant and equipment totaled $2,683 million and $1,881 million.

Other contingencies - During the second quarter of 2011, the AOSP operator determined the need and developed preliminary plans to address water flow into a previously mined and contained section of the Muskeg River mine. Our share of the estimated costs in the amount of $64 million was recorded to cost of revenues. At December 31, 2011, the remaining liability is $49 million.

Summary of Principal Accounting Policies	12 Months Ended Dec. 31, 2011
Accounting Policies [Abstract]	
Significant Accounting Policies	

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.

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 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.

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.

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.

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.

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.

Summary of Principal Accounting Policies (Policies)	12 Months Ended Dec. 31, 2011
Accounting Policies [Abstract]	
Nature Of Operations	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.
Consolidation Policy [Text Block]	***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, Policy [Policy Text Block]	***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 And Translations Policy [Text Block]	***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 Policy [Text Block]	***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.

Gas Balancing, Policy [Policy Text Block]

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 Policy [Text Block]

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.

Receivables, Policy [Policy Text Block]

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..

Inventory Policy [Text Block]

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.

Matching Buy Sell Policy [Text Block]

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.

Derivatives Policy [Text Block]

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.

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.

Derivatives, Methods of Accounting, Hedging Derivatives [Policy Text Block]

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, Methods of Accounting, Derivatives Not Designated or Qualifying as Hedges [Policy Text Block]

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.

Full Cost or Successful Efforts, Policy [Policy Text Block]

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.

Costs Incurred, Policy [Policy Text Block]

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.

Property Plant And Equipment Policy [Text Block]

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.

Impairment or Disposal of Long-Lived Assets, Policy [Policy Text Block]

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.

Property Plant And Equipment Dispositions Policy [Text Block]

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 and Intangible Assets, Policy [Policy Text Block]

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.

Property, Plant and Equipment, Planned Major Maintenance Activities, Policy [Policy Text Block]

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, Policy [Policy Text Block]

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, Policy [Policy Text Block]

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.

Income Tax Policy [Text Block]

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 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.

Share-based Compensation, Option and Incentive Plans Policy [Policy Text Block]

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.

Defined Benefit Postretirement Plans (Details 2) (USD $) In Millions, unless otherwise specified	12 Months Ended			
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Other Postretirement Benefit Plans Defined Benefit [Member]				
Defined Benefit Plan Net Periodic Benefit Cost [Line Items]				
Service cost for continuing operation		$ 4	$ 3	$ 3
Interest cost for continuing operation		16	16	18
Amortization:				
- prior service cost (credit)		(7)	(7)	(6)
Net periodic benefit cost		13	12	15
Other changes in plan assets and benefit obligations recognized in other comprehensive income (pretax):				
Actuarial loss (gain)		1	69	(34)
Amortization of actuarial loss		0	2	5
Amortization of prior service credit (cost)		7	6	5
Total recognized in other comprehensive income		8	77	(24)
Total recognized in net periodic benefit cost and other comprehensive income		21	89	(9)
Defined Benefit Plan Amounts That Will Be Amortized From Accumulated Other Comprehensive Income Loss In Next Fiscal Year Abstract				
Prior service cost to be amortized next year	7			
United States Pension Plans Of US Entity Defined Benefit [Member]				
Defined Benefit Plan Net Periodic Benefit Cost [Line Items]				
Service cost for continuing operation		28	30	36
Interest cost for continuing operation		44	47	46
Expected return on plan assets		(43)	(44)	(47)
Amortization:				
- prior service cost (credit)		6	6	6
-actuarial loss (gain)		47	48	20
- net settlement/curtailment loss		30	56	4
Net periodic benefit cost		112	143	65
Other changes in plan assets and benefit obligations recognized in other comprehensive income (pretax):				
Actuarial loss (gain)		97	211	587
Amortization of actuarial loss		(77)	(167)	(33)
Amortization of prior service credit (cost)		(6)	(13)	(13)
Spin-off downstream business		(24)		
Total recognized in other comprehensive income		(10)	31	541
Total recognized in net periodic benefit cost and other comprehensive income		102	174	606
Foreign Pension Plans Defined Benefit [Member]				
Defined Benefit Plan Net Periodic Benefit Cost [Line Items]				
Service cost for continuing operation		19	19	14
Interest cost for continuing operation		22	22	22

Expected return on plan assets		(23)	(22)	(21)
Amortization:				
- prior service cost (credit)				1
-actuarial loss (gain)		2	5	2
Other			2	
- net settlement/curtailment loss				18
Net periodic benefit cost		20	26	36
Other changes in plan assets and benefit obligations recognized in other comprehensive income (pretax):				
Actuarial loss (gain)		24	(25)	52
Amortization of actuarial loss		(2)	(5)	(7)
Prior service cost		(11)		
Amortization of prior service credit (cost)				(1)
Total recognized in other comprehensive income		11	(30)	44
Total recognized in net periodic benefit cost and other comprehensive income		31	(4)	80
United States and Foreign Pension Plans Defined Benefit [Member]				
Defined Benefit Plan Amounts That Will Be Amortized From Accumulated Other Comprehensive Income Loss In Next Fiscal Year Abstract				
Prior service cost to be amortized next year	7			
Net loss to be amortized next year	$ 46			

Inventories (Tables)	12 Months Ended Dec. 31, 2011
Inventories Note Tables [Abstract]	
Schedule of Inventory, Current [Table Text Block]	

(In millions)	December 31, 2011	December 31, 2010
Liquid hydrocarbons, natural gas and bitumen	$ 147	$ 1,275
Refined products and merchandise	0	1,774
Supplies and sundry items	214	404
Inventories at cost	$ 361	$ 3,453

Variable Interest Entities (Details) (Variable Interest Entity, Not Primary Beneficiary [Member], USD $) In Millions, unless otherwise specified	Dec. 31, 2011
Variable Interest Entity, Not Primary Beneficiary [Member]	
Variable Interest Entity [Line Items]	
Recorded liability related to unconsolidated VIE	$ 3
Maximum exposure to loss related to unconsolidated VIE	$ 715

Fair Value Measurements (Details-Recurring) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Fair value of assets on a recurring basis			
Derivative Assets	$ 5	$ 172	
Derivative Liabilities		(105)	
Reconciliation of net beginning and ending balances recorded for derivative instruments classified as Level 3 in the fair value hierarchy			
Beginning balance, net Level 3 fair value asset (liability)	(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 downstream businesses	2		
Ending balance, net Level 3 fair value asset (liability)	0	(2)	9
Unrealized gains(losses) included in net income related to Level 3 derivative instruments		(1)	(7)
Commodity [Member]			
Fair value of assets on a recurring basis			
Derivative Assets		140	
Derivative Liabilities		(105)	
Interest rate [Member]			
Fair value of assets on a recurring basis			
Derivative Assets	5	32	
Fair Value, Inputs, Level 1 [Member]			
Fair value of assets on a recurring basis			
Derivative Assets		58	
Derivative Liabilities		(102)	
Fair Value, Inputs, Level 1 [Member] | Commodity [Member]			
Fair value of assets on a recurring basis			
Derivative Assets		58	
Derivative Liabilities		(102)	
Fair Value Inputs Level 2 [Member]			
Fair value of assets on a recurring basis			
Derivative Assets	5	32	
Fair Value Inputs Level 2 [Member] | Interest rate [Member]			
Fair value of assets on a recurring basis			
Derivative Assets	5	32	
Fair Value, Inputs, Level 3 [Member]			

Fair value of assets on a recurring basis	
Derivative Assets	1
Derivative Liabilities	(3)
Fair Value, Inputs, Level 3 [Member] | Commodity [Member]	
Fair value of assets on a recurring basis	
Derivative Assets	1
Derivative Liabilities	(3)
Fair Value (no inputs) Collateral [Member]	
Fair value of assets on a recurring basis	
Derivative Assets	$ 81

Consolidated Statements of Income (USD $) In Millions, except Per Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Revenues and other income:			
Sales and other operating revenues	$ 14,603	$ 11,634	$ 8,465
Sales to related parties	60	56	59
Income (loss) 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)	0
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
Basic:			
Income from continuing operations, per basic share	$ 2.40	$ 2.65	$ 1.01
Discontinued operations, per basic share	$ 1.75	$ 0.97	$ 1.05
Net income, per basic share	$ 4.15	$ 3.62	$ 2.06
Diluted:			
Income from continuing operations, per diluted share	$ 2.39	$ 2.65	$ 1.01
Discontinued operations, per diluted share	$ 1.74	$ 0.96	$ 1.05
Net income, per diluted share	$ 4.13	$ 3.61	$ 2.06
Dividends paid, per share	$ 0.80	$ 0.99	$ 0.96
Weighted average common shares outstanding, basic	710	710	709
Weighted average common shares outstanding, diluted	714	712	711

Derivatives (Tables)

	12 Months Ended Dec. 31, 2011

Derivatives Note Tables [Abstract]

Derivatives as they appear on the Balance Sheet

(In millions)	December 31, 2010 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)	

(In millions)	December 31, 2010 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	

Effects of derivatives designated as cash flow hedges

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

Effects of derivatives designated as fair value hedges

(In millions)	Income Statement Location	Gain (Loss) 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

Effects of derivatives not designated as hedges

(In millions)	Income Statement Location	Gain (Loss) 2011	2010	2009
Commodity	Sales and other operating revenues	$ 5	$ 121	$ 90
Foreign currency	Net interest and other	0	0	3
		$ 5	$ 121	$ 93

Consolidated Statements of Cash Flows (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Net cash provided by continuing operatons:			
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	0
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 operating capital:			
Changes in current receivables	8	(409)	(188)
Changes in inventories	33	(71)	(104)
Changes in 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	0	0	1,491
Debt issuance costs	0	0	(11)
Debt repayments	(2,877)	(653)	(68)
Purchases of common stock	(300)	0	0
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	0
Net cash provided by (used in) financing activities	(2,295)	(1,355)	724

Effect of exchange rate changes on cash:			
Total effect of exchange rate changes on cash	(20)	0	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

Leases (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Operating Leases Future Minimum Payments Due Abstract			
Year 1	$ 42		
Year 2	38		
Year 3	29		
Year 4	26		
Year 5	25		
Later years, Operating Leases	66		
Sublease Rentals, Operating Leases	2		
Total minimum operating lease payments	224		
Capital Leases Future Minimum Payments Due Abstract			
Year 1	22		
Year 2	1		
Year 3	1		
Year 4	1		
Year 5	1		
Later years, Capital Leases	25		
Total minimum capital lease payments	51		
Less inputed interest costs	(20)		
Present value of net minimum capital lease payments	31		
Operating Leases Rent Expense Abstract			
Lease Payments Made On Our Behalf		16	3
Operating Leases, Rent Expense	$ 74	$ 77	$ 105

Segment Information (Details 2) (USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Reconciliation of segment income to net income:			
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)
Gain(loss) on dispositions, not allocated to segments	45	407	122
Impairments, not allocated to segements	(195)	(286)	(45)
Loss on early extinguishment of debt, after-tax	(176)	(57)	
Water abatement costs	(48)		
Deferred income tax items	(61)	(45)	
Gain on U.K. natural gas contracts, after-tax			37
Tax effect of subsidiary restructure	(122)		
Eagle Ford transaction costs	(10)		
Income from continuing operations	1,707	1,882	716
Discontinued operations	1,239	686	747
Net income	2,946	2,568	1,463
Reconciliation of total revenues to sales and other operating revenues (including consumer excise taxes) as reported in the consolidated statements of income:			
Total revenue	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

Dispositions (Tables)	12 Months Ended Dec. 31, 2011
Dispositions Note Tables [Abstract]	
Discontinued Operations Table	

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

Income Taxes (Details 3) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Foreign Source Income [Abstract]			
Foreign Source Income	$ 4,869	$ 4,563	$ 2,947
Undistributed Income of Certain Consolidated Foreign Subsidiaries [Abstract]			
Undistributed Income Of Certain Consolidated Foreign Subsidiaries	235		
Income Tax Expense If Not Permanently Reinvested	82		
Unrecognized Tax Benefit Rollforward [Abstract]			
Unrecognized Tax Benefits, Beginning Balance	103	75	39
Unrecognized Tax Benefits Increases Resulting From Current Period Tax Positions	4	28	30
Unrecognized Tax Benefits Decreases Resulting From Current Period Tax Positions		(1)	(2)
Unrecognized Tax Benefits Increases Resulting From Prior Period Tax Positions	87	25	30
Unrecognized Tax Benefits Decreases Resulting From Prior Period Tax Positions	(29)	(12)	(15)
Unrecognized Tax Benefits Decreases Resulting From Settlements With Taxing Authorities	(8)	(12)	(7)
Unrecognized Tax Benefits, Ending Balance	157	103	75
Unrecognized Tax Benefits That Would Impact Effective Tax Rate	103		
Significant Change In Unrecognized Tax Benefits Is Reasonably Possible Amount Of Unrecorded Benefit	19		
Unrecognized Tax Benefits Income Tax Penalties And Interest Accrued Abstract			
Unrecognized Tax Benefits Income Tax Penalties And Interest Accrued	27	15	
Unrecognized Tax Benefits Income Tax Penalties And Interest Expense Abstract			
Unrecognized Tax Benefits Income Tax Penalties And Interest Expense	$ 13	$ 5	$ 0
United States [Member]			
Income Tax Uncertainties [Line Items]			
Open Tax Years By Major Tax Jurisdiction	2004 - 2010		
Canada [Member]			
Income Tax Uncertainties [Line Items]			
Open Tax Years By Major Tax Jurisdiction	2006 - 2010		
Equatorial Guinea [Member]			
Income Tax Uncertainties [Line Items]			
Open Tax Years By Major Tax Jurisdiction	2006 - 2010		
Libya [Member]			
Income Tax Uncertainties [Line Items]			

Open Tax Years By Major Tax Jurisdiction	2006 - 2009
Norway [Member]	
Income Tax Uncertainties [Line Items]	
Open Tax Years By Major Tax Jurisdiction	2008 - 2010
United Kingdom [Member]	
Income Tax Uncertainties [Line Items]	
Open Tax Years By Major Tax Jurisdiction	2008 - 2010

Fair Value Measurements	12 Months Ended Dec. 31, 2011
Fair Value Measurements Disclosure [Abstract]	
Fair Value Disclosures [Text Block]	**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.

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	0	0	85	64	311	154
Intangible assets	0	25	0	0	0	0
Equity method investments	0	0	0	25	0	0

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 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.

Income per Common Share (Tables)	12 Months Ended Dec. 31, 2011
Earnings Per Share [Abstract]	
Schedule of Earnings Per Share, Basic and Diluted [Table Text Block]	

	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

Debt	12 Months Ended Dec. 31, 2011
Debt Disclosure [Abstract]	
Debt	

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	$ 0	$ 0
6.125% notes due 2012	0	450
6.000% notes due 2012	0	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	0	700
7.500% debentures due 2019 [a]	228	688
6.000% debentures due 2017 [a]	682	682
9.375% debentures due 2022	32	32
8.500% debentures due 2023	70	70
8.125% debentures due 2023	131	131
6.600% debentures due 2037	750	750
4.550% promissory note, semi-annual payments due 2012 - 2015	272	340
Series A medium term notes due 2022	3	3
4.750% - 6.875% obligations relating to industrial development and environmental improvement bonds and notes due 2013 - 2033	0	198
5.375% obligation relating to revenue bonds due 2013	23	23
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Sale-leaseback financing due 2012	11	20
Capital lease obligation due 2012	9	17
Consolidated subsidiaries		
8.375% secured notes due 2012 [a]	0	448
Capital lease obligations due 2012 - 2034		
Downstream business	0	279
Other	11	12
Total [b]	4,793	7,854
Unamortized fair value differential for debt assumed in acquisitions	0	16
Unamortized discount	(10)	(16)
Fair value adjustments [c]	32	42
Amounts due within one year	(141)	(295)
Total long-term debt due after one year	$ 4,674	$ 7,601

(a) These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.

(b) In the event of a change in control, as defined in the related agreements, debt obligations totaling $431 million at December 31, 2011, may be declared immediately due and payable.

(c) See Note 15 for information on interest rate swaps.

The termination date on $2,625 million of our revolving credit facility is May 2013. The remaining $375 million has a termination date of May 2012. The facility requires a representation at an initial borrowing that there has been no change in our consolidated financial position or operations, considered as a whole which would materially and adversely affect our ability to perform our obligations under the revolving credit facility. Interest on the facility is based on defined short-term market rates. During the term of the agreement, we are obligated to pay a variable facility fee on the total commitment, which at December 31, 2011 was 0.10 percent.

Our long-term debt agreements do not contain restrictive financial covenants.

On December 31, 2010, we were obligated (primarily or contingently) for $221 million of debt for which United States Steel assumed responsibility for repayment. During the fourth quarter of 2011, United States Steel called all industrial development and environmental improvement bonds and notes for which they had assumed responsibility.

The following table shows five years of debt payments:

(In millions)		
2012	$	141
2013		205
2014		68
2015		68
2016		0

In February and March 2011, we retired the following debt at a weighted average price equal to 112 percent of face value. A $279 million loss on early extinguishment of debt was recognized in the first quarter of 2011. The loss includes related deferred financing and premium costs partially offset by the gain on settled interest rate swaps.

(In millions)		
6.000% notes due 2012	$	400
6.125% notes due 2012		450
8.375% secured notes due 2012 {a}		448
6.500% debentures due 2014		700
5.900% notes due 2018		40
7.500% debentures due 2019		460
Total debt purchases	$	2,498

(a) These notes were senior secured notes of Marathon Oil Canada Corporation.

In April 2010, we retired $500 million in aggregate principal of our debt under two tender offers at a weighted average price equal to 117 percent of face value. As a result, we recorded a loss on early extinguishment of debt of $92 million, including the transaction premium as well as the expensing of related deferred financing costs on the debt in the second quarter of 2010.

Property, Plant and Equipment (Details) (USD $) In Millions, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Segment Reporting Information [Line Items]		
Less accumulated depreciation, depletion and amortization	$ (17,248)	$ (19,805)
Property, plant and equipment, net	25,324	32,222
PPE gross assets capital leases	13	272
Accumulated DDA capital leases	1	48
United States Exploration and Production [Member]		
Segment Reporting Information [Line Items]		
Total property, plant and equipment	19,679	13,532
International Exploration and Production [Member]		
Segment Reporting Information [Line Items]		
Total property, plant and equipment	12,579	11,736
Exploration and Production Segment [Member]		
Segment Reporting Information [Line Items]		
Total property, plant and equipment	32,258	25,268
Integrated Gas Segment [Member]		
Segment Reporting Information [Line Items]		
Total property, plant and equipment	37	47
Oil Sands Mining Segment [Member]		
Segment Reporting Information [Line Items]		
Total property, plant and equipment	9,936	9,631
Refining, Marketing and Transportation Segment [Member]		
Segment Reporting Information [Line Items]		
Total property, plant and equipment	0	16,624
Corporate [Member]		
Segment Reporting Information [Line Items]		
Total property, plant and equipment	341	457
Libya [Member]		
Segment Reporting Information [Line Items]		
Property, plant and equipment, net	756	
Proved Developed and Undeveloped Reserves, Net	239	
Total All Segments [Member]		
Segment Reporting Information [Line Items]		
Total property, plant and equipment	42,572	52,027
Property, plant and equipment, net		$ 32,222

Consolidated Statements of Stockholders Equity (USD $) In Millions	Total	Preferred Stock [Member]	Common Stock [Member]	Common Stock Securities Exchangable [Member]	Treasury Stock [Member]	Additional Paid In Capital [Member]	Retained Earnings [Member]	Accumulated Other Comprehensive Income (Loss) [Member]	Noncontrolling Interest
Balance as of at Dec. 31, 2008	$ 21,409	$ 0	$ 767	$ 0	$ (2,720)	$ 6,696	$ 17,259	$ (593)	$ 0
Shares Balance as of at Dec. 31, 2008		3	767	3	(61)				
Shares issued - stock based compensation	11				20	(9)			
Shares exchanged	0		2			(2)			
Shares exchanged, shares		(2)	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)		
Balance as of at Dec. 31, 2009	21,910	0	769	0	(2,706)	6,738	18,043	(934)	0
Shares Balance as of at Dec. 31, 2009		1	769	1	(61)				
Shares issued - stock based compensation	34				46	(12)			
Shares issued - stock based compensation, shares					1				
Shares exchanged	0		1			(1)			
Shares exchanged, shares		(1)	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)		
Balance as of at Dec. 31, 2010	23,771	0	770	0	(2,665)	6,756	19,907	(997)	0
Shares Balance as of at Dec. 31, 2010		0	770	0	(60)				
Shares issued - stock based compensation	172				257	(85)			
Shares issued - stock based compensation, shares					6				
Shares repurchased	(308)				(308)				
Shares repurchased, shares	12				12				
Stock-based compensation	4					4			
Net income	2,946						2,946		
Other comprehensive loss	40							40	
Dividends paid	(567)						(567)		
Purchase of subsidiary shares from noncontrolling interest	7								7
Distribution related to spin-off of downstream business	(8,906)					5	(9,498)	587	
Balance as of at Dec. 31, 2011	$ 17,159	$ 0	$ 770	$ 0	$ (2,716)	$ 6,680	$ 12,788	$ (370)	$ 7
Shares Balance as of at Dec. 31, 2011		0	770	0	(66)				

Consolidated Statements of Comprehensive Income (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Consolidated Statements of Comprehensive Income			
Net income	$ 2,946	$ 2,568	$ 1,463
Post retirement and post employment plans			
Change in actuarial loss	16	(76)	(564)
Spin off downstream business	968		
Income tax benefit on post retirement and post employment plans	(357)	7	208
Post retirement and post-employment plans, net of tax	627	(69)	(356)
Derivative hedges			
Net unrecognized gain (loss)	9	5	24
Spin off downstream business	(7)		
Income tax benefit (provision) on derivatives hedges	(1)	1	(12)
Derivative hedges, net of tax	1	6	12
Foreign currency translation and other			
Unrealized gain (loss)	(1)	0	4
Income tax benefit (provision) on foreign currency translation and other	0	0	(1)
Foreign currency translation and other, net of tax	(1)	0	3
Other comprehensive income (loss)	627	(63)	(341)
Comprehensive income	$ 3,573	$ 2,505	$ 1,122

Income Taxes	12 Months Ended Dec. 31, 2011

Income Taxes Disclosure [Abstract]

Income Taxes

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

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.

Deferred tax assets and liabilities resulted from the following:

	December 31,	
(In millions)	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	0	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. 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	0	(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.

Stockholders' Equity (Details) (USD $) Share data in Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011
Stockholders Equity Details [Abstract]	
Treasury Stock Amount Of Repurchase Authorization	$ 5,000,000,000
Shares repurchased	300,000,000
Shares repurchased, shares	12
Authorized Stock Repurchase Program Repurchased Number Of Shares	78
Authorized Stock Repurchase Program Repurchase Amount	$ 3,222,000,000

Stock-Based Compensation Plans (Details 4-Restricted) (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Restricted Stock			
Beginning year unvested restricted stock	2,084,680		
Granted restricted stock	3,066,978		
Vested restricted stock	(993,949)		
Forfeited restricted stock	(163,806)		
Share based compensation arrangement by share based payment award equity instruments other than options spin off in period	(289,925)		
End of year unvested restricted stock	3,703,978	2,084,680	
Beginning year weighted average grant date fair value unvested restricted stock	$ 23.03	$ 44.89	
Granted restricted stock weighted average grant date fair value restricted stock	$ 27.74		
Vested restricted stock weighted average grant date fair value restricted stock	$ 27.34		
Forfeited restricted stock weighted average grant date fair value restricted stock	$ 23.88		
Downstream spin-off weighted average grant date fair value restricted stock	$ 21.30		
End of year weighted average grant date fair value unvested restricted stock	$ 25.88	$ 23.03	$ 44.89
Restricted Stock vesting date fair value	$ 30	$ 21	$ 24
Restricted stock unrecognized compensation cost	$ 78		
Restricted stock weighted average grant date fair value	$ 25.88	$ 23.03	$ 44.89
Restricted stock unrecognized compensation cost weighted average period recognized	2.5		

Document and Entity Information (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended Dec. 31, 2011
Document and Entity Information [Abstract]	
Document Type	10-K
Document Period End Date	Dec. 31, 2011
Document Fiscal Period Focus	FY
Document Fiscal Year Focus	2011
Amendment Flag	false
Entity Registrant Name	Marathon Oil Corporation
Entity Central Index Key	0000101778
Entity Current Reporting Status	Yes
Entity Voluntary Filers	No
Current Fiscal Year End Date	--12-31
Entity Filer Category	Large Accelerated Filer
Entity Well Known Seasoned Issuer	Yes
Entity Common Stock Shares Outstanding	703,925,642
Entity Public Float	$ 22,773

Inventories	12 Months Ended Dec. 31, 2011
Inventories Disclosure [Abstract]	
Inventories	

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).

	December 31,			
(In millions)	2011		2010	
Liquid hydrocarbons, natural gas and bitumen	$	147	$	1,275
Refined products and merchandise		0		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.

Asset Retirement Obligations (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended	
	Dec. 31, 2011	Dec. 31, 2010
Asset Retirement Obligation Disclosure [Abstract]		
Asset retirement obligation beginning balance	$ 1,355	$ 1,102
Incurred, including acquisitions	37	49
Settled	(39)	(28)
Accretion expense (including depreciation, depletion, and amortization)	81	70
Revisions to previous estimates	126	162
Spin-off downstream business	(50)	
Asset retirement obligation ending balance	1,510	1,355
Asset retirement obligation classified as short-term		$ 1

Stock-Based Compensation Plans (Details 3-Stock Options) (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended Dec. 31, 2011
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	
Number of Shares Under Option Outstanding	21,370,715
Weighted Average Remaining Contractual Life Outstanding	6
Weighted Average Exercise Price Outstanding	$ 24.41
Number of Shares Under Option Exercisable	13,105,460
Weighted Average Exercise Price Exercisable	$ 24.11
Aggregate intrinsic value of stock option awards outstanding	$ 146
Aggregate intrinsic value of stock option awards currently exercisable	98
Weighted average remaining contractual life of stock option awards currently exercisable	5
Number of fully-vested stock option awards and stock option awards expected to vest	21,142,660
Weighted average exercise price of fully-vested stock option awards and stock option awards expected to vest	$ 24.38
Remaining contractual life of fully-vested stock option awards and stock option awards expected to vest	6
Aggregate intrinsic value of fully-vested stock option awards and stock option awards expected to vest	145
Unrecognized compensation cost related to stock option awards	$ 36
Weighted average period over which unrecognized compensation costs are expected to be recognized	2
Range of Exercise Prices First [Member]	
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	
Number of Shares Under Option Outstanding	1,272,745
Weighted Average Remaining Contractual Life Outstanding	2
Weighted Average Exercise Price Outstanding	$ 10.23
Number of Shares Under Option Exercisable	1,272,745
Weighted Average Exercise Price Exercisable	$ 10.23
Range of Exercise Prices Second [Member]	
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	
Number of Shares Under Option Outstanding	2,850,590
Weighted Average Remaining Contractual Life Outstanding	5
Weighted Average Exercise Price Outstanding	$ 15.21
Number of Shares Under Option Exercisable	2,354,373
Weighted Average Exercise Price Exercisable	$ 15.28
Range of Exercise Prices Third [Member]	
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	

Number of Shares Under Option Outstanding	6,642,268
Weighted Average Remaining Contractual Life Outstanding	8
Weighted Average Exercise Price Outstanding	$ 18.60
Number of Shares Under Option Exercisable	2,810,120
Weighted Average Exercise Price Exercisable	$ 18.52
Range of Exercise Prices Fourth [Member]	
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	
Number of Shares Under Option Outstanding	2,021,400
Weighted Average Remaining Contractual Life Outstanding	4
Weighted Average Exercise Price Outstanding	$ 23.92
Number of Shares Under Option Exercisable	1,955,767
Weighted Average Exercise Price Exercisable	$ 23.82
Range of Exercise Prices Fifth [Member]	
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	
Number of Shares Under Option Outstanding	22,388
Weighted Average Remaining Contractual Life Outstanding	7
Weighted Average Exercise Price Outstanding	$ 29.56
Number of Shares Under Option Exercisable	22,388
Weighted Average Exercise Price Exercisable	$ 29.56
Range of Exercise Prices Sixth [Member]	
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range End Of Period [Line Items]	
Number of Shares Under Option Outstanding	8,561,324
Weighted Average Remaining Contractual Life Outstanding	7
Weighted Average Exercise Price Outstanding	$ 34.20
Number of Shares Under Option Exercisable	4,690,067
Weighted Average Exercise Price Exercisable	$ 35.75

Consolidated Balance Sheets (USD $) In Millions, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
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, current	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
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, current	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 tax liabilities, noncurrent	2,544	3,569
Defined benefit postretirement plan obligations	789	2,171
Asset retirement obligations	1,510	1,354
Deferred credits and other liabilities, noncurrent	301	435
Total liabilities	14,212	26,243
Stockholders' Equity		
Preferred stock no shares issued oroutstanding (no par value, 26 million shares authorized)	0	0
Common stock issued - 770 million and 770 million shares (par value $1 per share, 1.1 billion shares authorized)	770	770
Common stock, securities exchangeable into common stock - no shares issued or outstanding (no par value, 29 million shares authorized)	0	0
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)

Noncontrolling interest	7	0
Total equity of Marathon Oil stockholders	17,152	23,771
Total stockholders' equity	17,159	23,771
Total liabilities and stockholders' equity	$ 31,371	$ 50,014

Acquisitions	12 Months Ended Dec. 31, 2011
Significant Acquisitions Disclosure [Abstract]	
Significant Acquisitions Disclosure [Text Block]	

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.

Variable Interest Entities	12 Months Ended Dec. 31, 2011
Variable Interest Entities Disclosure [Abstract]	
Variable Interest Entities [Text Block]	**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 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.

Derivatives	12 Months Ended Dec. 31, 2011
Derivatives Disclosure [Abstract]	
Derivatives	

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.

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

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		0	0	3
		$	5$	121$	93

Equity Method Investments and Related Party Transactions	12 Months Ended Dec. 31, 2011
Equity Method Investments And Related Party Transactions Disclosure [Abstract]	
Equity Method Investments And Related Party Transactions Disclosure [Text Block]	(see below)

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:

(In millions)	Ownership as of December 31, 2011	December 31, 2011	December 31, 2010
EGHoldings	60%	$ 875	$ 927
Alba Plant LLC	52%	272	303
AMPCO	45%	191	210
Downstream business investments		0	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.

Defined Benefit Postretirement Plans (Details 3)	12 Months Ended			
	Dec. 31, 2012	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Other Postretirement Benefit Plans Defined Benefit [Member]				
Defined Benefit Plan, Weighted Average Assumptions Used in Calculating Benefit Obligation [Abstract]				
Discount rate		4.90%	5.55%	5.95%
Rate of compensation increase		5.00%	5.00%	4.50%
Defined Benefit Plan, Weighted Average Assumptions Used in Calculating Net Periodic Benefit Cost [Abstract]				
Discount rate (net periodic benefit cost)		5.55%	6.85%	6.85%
Rate of compensation increase		5.00%	4.50%	4.50%
United States Pension Plans Of US Entity Defined Benefit [Member]				
Defined Benefit Plan, Weighted Average Assumptions Used in Calculating Benefit Obligation [Abstract]				
Discount rate		4.45%	5.05%	5.50%
Rate of compensation increase		5.00%	5.00%	4.50%
Defined Benefit Plan, Weighted Average Assumptions Used in Calculating Net Periodic Benefit Cost [Abstract]				
Discount rate (net periodic benefit cost)		5.05%	5.23%	6.90%
Expected long-term return on plan assets	7.75%	8.50%	8.50%	8.50%
Rate of compensation increase		5.00%	4.50%	4.50%
Foreign Pension Plans Defined Benefit [Member]				
Defined Benefit Plan, Weighted Average Assumptions Used in Calculating Benefit Obligation [Abstract]				
Discount rate		4.70%	5.40%	5.70%
Rate of compensation increase		4.30%	5.10%	5.55%
Defined Benefit Plan, Weighted Average Assumptions Used in Calculating Net Periodic Benefit Cost [Abstract]				
Discount rate (net periodic benefit cost)		5.40%	5.70%	6.70%
Expected long-term return on plan assets		5.86%	6.40%	6.10%
Rate of compensation increase		5.10%	5.55%	4.75%

Segment Information	12 Months Ended Dec. 31, 2011

Segment Information Disclosure [Abstract]

Segment Information

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 6, 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.

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	0	0	47
Related parties	60	0	0	60
Segment revenues	13,029	1,588	93	14,710
Elimination of intersegment revenues	(47)	0	0	(47)
Total revenues	$ 12,982	$ 1,588	$ 93	$ 14,663
Segment income	$ 2,157	$ 256	$ 178	$ 2,591
Income from equity method investments	249	0	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	0	0	75
Related parties	56	0	0	56
Segment revenues	10,782	833	150	11,765
Elimination of intersegment revenues	(75)	0	0	(75)
Total revenues	$ 10,707	$ 833	$ 150	$ 11,690
Segment income (loss)	$ 1,941	$ (50)	$ 142	$ 2,033
Income from equity method investments	188	0	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	0	0	28
Related parties	59	0	0	59
Segment revenues	7,738	692	50	8,480
Elimination of intersegment revenues	(28)	0	0	(28)
Gain on U.K. natural gas contracts {a}	72	0	0	72 {a}
Total revenues	$ 7,782	$ 692	$ 50	$ 8,524
Segment income	$ 1,218	$ 44	$ 90	$ 1,352
Income from equity method investments	125	0	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.

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)	0
Tax effect of subsidiary restructuring	(122)	0	0
Deferred income taxes	(61)	(45)	0
Water abatement - Oil Sands	(48)	0	0
Eagle Ford transaction costs	(10)	0	0
Gain on dispositions {b}	45	407	122
Gain on U.K. natural gas contracts	0	0	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

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

Segment Information (Details 3) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
United States [Member]			
Revenues From External Customers And Long-Lived Assets [Line Items]			
Total revenues	$ 6,971	$ 5,363	$ 3,326
Long-Lived Assets	10,928	18,415	
Canada [Member]			
Revenues From External Customers And Long-Lived Assets [Line Items]			
Total revenues	1,588	833	692
Long-Lived Assets	9,711	9,564	
Equatorial Guinea [Member]			
Revenues From External Customers And Long-Lived Assets [Line Items]			
Long-Lived Assets	2,214	2,389	
Norway [Member]			
Revenues From External Customers And Long-Lived Assets [Line Items]			
Total revenues	3,386	2,243	1,617
Long-Lived Assets	1,133	1,353	
Other International [Member]			
Revenues From External Customers And Long-Lived Assets [Line Items]			
Total revenues	956	715	607
Long-Lived Assets	2,721	2,399	
UK [Member]			
Revenues From External Customers And Long-Lived Assets [Line Items]			
Total revenues	1,546	1,063	1,143
Libya 1 [Member]			
Revenues From External Customers And Long-Lived Assets [Line Items]			
Total revenues	$ 216	$ 1,473	$ 1,139

Dispositions	12 Months Ended Dec. 31, 2011
Dispositions Disclosure [Abstract]	
Dispositions	

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 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

Income per Common Share	12 Months Ended Dec. 31, 2011

Income Per Common Share Disclosure [Abstract]

Income Per Common Share

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.

Other Items	12 Months Ended Dec. 31, 2011

Other Items Disclosure [Abstract]

Other Items

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)

Income Taxes (Details 2) (USD $) In Millions, unless otherwise specified	6 Months Ended	12 Months Ended		
	Jun. 30, 2011	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Valuation Allowance [Abstract]				
Change in federal valuation allowances		$ 585	$ (74)	$ 280
Change in foreign valuation allowances	(228)	52	40	(79)
Deferred Tax Assets Liabilities Net [Abstract]				
Deferred Tax Assets Gross Current		99		
Deferred Tax Assets Gross Noncurrent		674		
Deferred Tax Liabilities Current		5	324	
Deferred Tax Liabilities Noncurrent		2,544	3,569	
Net Deferred Tax Liabilities		1,776	3,893	
Foreign Country Canada [Member]				
Operating Loss Carryforwards [Line Items]				
Deferred Tax Assets Operating Loss Carryforwards		811		
Foreign Country Indonesia [Member]				
Operating Loss Carryforwards [Line Items]				
Deferred Tax Assets Operating Loss Carryforwards		245		
State And Local Jurisdiction [Member]				
Operating Loss Carryforwards [Line Items]				
Deferred Tax Assets Operating Loss Carryforwards		$ 915		

Defined Benefit Postretirement Plans (Details 4) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
One percent point change in assumed health care cost trend rates			
Effect on total of service and interest cost components 1- Percentage increase	2		
Effect on total of service and interest cost components 1- Percentage decrease	2		
Effect on other postretirement benefit obligations 1- Percentage increase	33		
Effect on other postretirement benefit obligations 1- Percentage decrease	27		
Medical Pre-65 [Member]			
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]			
Health care cost trend rate assumed for the following year:	7.50%	7.50%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate:	2018	2018	2014
Medical Post-65 [Member]			
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]			
Health care cost trend rate assumed for the following year:	7.00%	7.00%	6.75%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate:	2017	2017	2015
Assumed Health Care Cost Prescription Drugs [Member]			
Defined Benefit Plan Assumed Health Care Cost Trend Rates [Line Items]			
Health care cost trend rate assumed for the following year:	7.50%	7.50%	7.50%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate:	2018	2018	2015

Inventories (Details) (USD $) In Millions, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Inventories Note Tables [Abstract]		
Liquid hydrocarbons natural gas and bitumen	$ 147	$ 1,275
Refined products and merchandise	0	1,774
Supplies and sundry items	214	404
Inventories	361	3,453
Percentage of total inventory at LIFO	16.00%	85.00%
Current acquisition costs in excess of LIFO	$ 74	$ 4,166

Income Taxes (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Federal Income Tax Expense Benefit Continuing Operations [Abstract]			
Current Federal Tax Expense Benefit	$ (210)	$ (279)	$ 40
Deferred Federal Income Tax Expense Benefit	(206)	(267)	(329)
Federal Income Tax Expense Benefit Continuing Operations	(416)	(546)	(289)
State And Local Income Tax Expense Benefit Continuing Operations [Abstract]			
Current State And Local Tax Expense Benefit	24	2	(19)
Deferred State And Local Income Tax Expense Benefit	82	(10)	5
State And Local Income Tax Expense Benefit Continuing Operations	106	(8)	(14)
Foreign Income Tax Expense Benefit Continuing Operations [Abstract]			
Current Foreign Tax Expense Benefit	3,088	2,941	1,480
Deferred Foreign Income Tax Expense Benefit	(58)	(212)	870
Foreign Income Tax Expense Benefit Continuing Operations	3,030	2,729	2,350
Current Income Tax Expense Benefit	2,902	2,664	1,501
Deferred income taxes	(182)	(489)	546
Provision for income taxes	2,720	2,175	2,047
Effective Tax Rate Reconciliation [Abstract]			
Statutory rate applied to income from continuing operations before income taxes	35.00%	35.00%	35.00%
Effects of foreign operations, including foreign tax credits	6.00%	20.00%	16.00%
Changes in permanent reinvestment assertion	5.00%		
Foreign currency remeasurement (gain) loss			11.00%
Adjustments to valuation allowances	14.00%	(2.00%)	10.00%
Tax law changes	1.00%	1.00%	
Other adjustments to effective tax rate			2.00%
Effective income tax rate on continuing operations	61.00%	54.00%	74.00%
Statutory Income Tax rate in Libya	in excess of 90 percent		
U.S. deferred tax on foreign undistributed earnings	716		
Undistributed Earnings of Foreign Operations	2,046		
United states foreign tax credits	488		
Previous UK supplemental tax rate	20.00%		
UK supplemental tax rate effective March 2011	32.00%		
Deferred tax expense due to foreign tax law change	10		
Deferred tax asset write-off due to health care reform acts		45	
Deferred tax asset write-off due to state tax law change	32		
Deferred Tax Assets Gross [Abstract]			
Deferred Tax Assets Employee Benefits	413	1,079	

Operating Loss Carryforwards	376	285
Deferred Tax Assets Tax Credit Carryforwards Foreign	3,005	2,045
Deferred Tax Assets Other	88	141
Deferred Tax Assets Valuation Allowance Federal	(791)	(206)
Deferred Tax Assets Valuation Allowance State	(61)	(48)
Deferred Tax Assets Valuation Allowance Foreign	(194)	(142)
Deferred Tax Assets	2,836	3,154
Deferred Tax Liabilities [Abstract]		
Deferred Tax Liabilities Property Plant And Equipment	3,283	5,292
Deferred Tax Liabilities Inventories		597
Deferred Tax Liabilities Consolidated Subsidiaries	1,286	1,116
Deferred Tax Liabilities Other	43	42
Deferred Tax Liabilities	4,612	7,047
Net Deferred Tax Liabilities	$ 1,776	$ 3,893

Stock-Based Compensation Plans (Details 5-Performance Unit) (USD $) In Millions, except Share data, unless otherwise specified	**12 Months Ended**	
	Dec. 31, 2011	**Dec. 31, 2009**
Performance Unit Disclosures [Abstract]		
Performance Unit Target Value Per Unit	$ 1	
Award instruments other than options performance unit minimum value	$ 0	
Performance Unit Maximum Value Per Unit	$ 2	
Award instruments other than options performance unit compensation expense	$ 32	$ 2
Performance Unit Compensation Expense Accelerated	$ 14	
Performance Unit Granted	15	

Acquisitions (Tables)	12 Months Ended Dec. 31, 2011
Business Acquisition, Purchase Price Allocation [Abstract]	
Schedule of Purchase Price Allocation [Table Text Block]	

(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

Leases (Tables)

Leases (Tables)	12 Months Ended Dec. 31, 2011	
Leases Note Tables [Abstract]		
Future minimum commitments for capital lease obligations and operating lease obligations		

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2012	$ 22	$ 42
2013	1	38
2014	1	29
2015	1	26
2016	1	25
Later years	25	66
Sublease rentals	0	(2)
Total minimum lease payments	$ 51	$ 224
Less imputed interest costs	(20)	
Present value of net minimum lease payments	$ 31	

Goodwill	12 Months Ended Dec. 31, 2011
Goodwill Disclosure [Abstract]	
Goodwill Disclosure [Text Block]	(see below)

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.

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

Supplemental Cash Flow Information	12 Months Ended Dec. 31, 2011
Supplemental Cash Flow Information Disclosure [Abstract]	
Supplemental Cash Flow Information	(see below)

19. Supplemental Cash Flow Information

(In millions)	2011	2010	2009
Net cash provided from operating activities included:			
Interest paid (net of amounts capitalized)	$ 268	$ 107	$ 19
Income taxes paid to taxing authorities	2,893	2,155	1,663
Commercial paper and revolving credit arrangements, net:			
Commercial paper - issuances	$ 421	$ -	$ 897
- repayments	(421)	-	(897)
Total	$ -	$ -	$ -
Noncash investing and financing activities related to continuing operations:			
Additions to property, plant and equipment			
Asset retirement costs capitalized, excluding acquisitions	$ 151	$ 207	$ 135
Change in capital expenditure accrual	104	(140)	(28)
Debt payments made by United States Steel	214	105	144
Capital lease and sale-leaseback financing obligations increase	-	-	9

Commitments and Contingencies (Details) (USD $) In Millions, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2011 Water abatement Oil Sands [Member]	Jun. 30, 2011 Water abatement Oil Sands [Member]	Dec. 31, 2011 Other Guarantee [Member]	Dec. 31, 2011 Clairton [Member]
Commitments And Contingencies [Abstract]						
Accrued Liabilities for remediation	$ 1	$ 119				
Guarantee Obligations [Line Items]						
Maximum potential undiscounted payments under guarantees					139	110
Commitments to acquire property, plant and equipment	2,683	1,881				
Site Contingency [Line Items]						
Site Contingency, Accrual, Undiscounted Amount			$ 49	$ 64		

Defined Benefit Postretirement Plans (Tables)	12 Months Ended Dec. 31, 2011
Defined Benefit Postretirement Plans Note Tables [Abstract]	
Schedule of Accumulated Benefit Obligations in Excess of Fair Value of Plan Assets [Table Text Block]	(table below)

	December 31,		
	2011		2010
(In millions)	U.S.	Int'l	U.S.
Projected benefit obligation	$ (986)	$ (465)	$ (3,221)
Accumulated benefit obligation	(813)	(418)	(2,365)
Fair value of plan assets	516	412	1,798

Summary Of Defined Benefit Pension Plans With Accumulated Benefit Obligations In Excess Of Plan Assets [Table Text Block]

	Pension Benefits				Other Benefits	
	2011		2010		2011	2010
(In millions)	U.S.	Int'l	U.S.	Int'l		
Change in benefit obligations:						
Benefit obligations at January 1	$ 3,221	$ 415	$ 2,989	$ 395	$ 779	$ 685
Spin-off downstream business	(2,308)	0	0	0	(483)	0
Service cost	28	19	92	19	4	18
Interest cost	44	22	153	22	16	39
Plan amendment	0	11	0	0	0	0
Actuarial loss	84	13	287	6	1	69
Foreign currency exchange rate changes	0	(2)	0	(18)	0	0
Other	0	0	0	6	0	0
Benefits paid	(83)	(13)	(300)	(15)	(16)	(32)
Benefit obligations at December 31	$ 986	$ 465	$ 3,221	$ 415	$ 301	$ 779
Change in plan assets:						
Fair value of plan assets at January 1	$ 1,798	$ 389	$ 1,623	$ 348	$ 0	$ 0
Spin-off downstream business	(1,268)	0	0	0	0	0
Actual return on plan assets	30	15	214	47	0	0
Employer contributions	39	23	267	20	0	0
Foreign currency exchange rate changes	0	(2)	0	(14)	0	0
Other	0	0	(6)	3	0	0
Benefits paid	(83)	(13)	(300)	(15)	0	0
Fair value of plan assets at December 31	$ 516	$ 412	$ 1,798	$ 389	$ 0	$ 0
Funded status of plans at December 31	$ (470)	$ (53)	$ (1,423)	$ (26)	$ (301)	$ (779)
Amounts recognized in the consolidated balance sheet:						
Current liabilities	(17)	0	(21)	0	(18)	(36)
Noncurrent liabilities	(453)	(53)	(1,402)	(26)	(283)	(743)
Accrued benefit cost	$ (470)	$ (53)	$ (1,423)	$ (26)	$ (301)	$ (779)
Pretax amounts in accumulated other comprehensive income:						
Net loss	$ 432	$ 63	$ 1,382	$ 41	$ 16	$ 18
Prior service cost (credit)	27	11	81	0	(18)	(24)

Schedule Of Net Periodic Benefit Cost And Other

Pension Benefits

Comprehensive Income [Table Text Block]

(In millions)	2011 U.S.	2011 Int'l	2010 U.S.	2010 Int'l	2009 U.S.	2009 Int'l	Other Benefits 2011	Other Benefits 2010	Other Benefits 2009
Components of net periodic benefit cost related to continuing operations:									
Service cost	$ 28	$ 19	$ 30	$ 19	$ 36	$ 14	$ 4	$ 3	$ 3
Interest cost	44	22	47	22	46	22	16	16	18
Expected return on plan assets	(43)	(23)	(44)	(22)	(47)	(21)	-	-	-
- prior service cost (credit)	6	-	6	-	6	1	(7)	(7)	(6)
- actuarial loss	47	2	48	5	20	2	-	-	-
Other	-	-	-	2	-	-	-	-	-
Net settlement/curtailment loss [a]	30	-	56	-	4	18	-	-	-
Net periodic benefit cost [b]	$ 112	$ 20	$ 143	$ 26	$ 65	$ 36	$ 13	$ 12	$ 15
Other changes in plan assets and benefit obligations recognized in other comprehensive income (pretax):									
Actuarial loss (gain)	$ 97	$ 24	$ 211	$ (25)	$ 587	$ 52	$ 1	$ 69	$ (34)
Amortization of actuarial (loss) gain	(77)	(2)	(167)	(5)	(33)	(7)	-	2	5
Prior service cost	-	(11)	-	-	-	-	-	-	-
Amortization of prior service credit (cost)	(6)	-	(13)	-	(13)	(1)	7	6	5
Spin off downstream business	(24)	-	-	-	-	-	-	-	-
Total recognized in other comprehensive income	$ (10)	$ 11	$ 31	$ (30)	$ 541	$ 44	$ 8	$ 77	$ (24)
Total recognized in net periodic benefit cost and other comprehensive income	$ 102	$ 31	$ 174	$ (4)	$ 606	$ 80	$ 21	$ 89	$ (9)

(a) Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. plans in 2011 and 2010. Additionally, in 2009 a curtailment and settlement was recorded related to our discontinued operations in Ireland as discussed in Note 6.

(b) Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

Schedule of Assumptions Used [Table Text Block]

	Pension Benefits						Other Benefits		
	2011		2010		2009				
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2011	2010	2009
Weighted average assumptions used to determine benefit obligation:									
Discount rate	4.45%	4.70%	5.05%	5.40%	5.50%	5.70%	4.90%	5.55%	5.95%
Rate of compensation increase	5.00%	4.30%	5.00%	5.10%	4.50%	5.55%	5.00%	5.00%	4.50%
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	5.05%	5.40%	5.23%	5.70%	6.90%	6.70%	5.55%	6.85%	6.85%
Expected long-term return on plan assets [a]	8.50%	5.86%	8.50%	6.40%	8.50%	6.10%	-	-	-
Rate of compensation increase	5.00%	5.10%	4.50%	5.55%	4.50%	4.75%	5.00%	4.50%	4.50%

a. Due to the revised targeted asset allocation as discussed under the plan investment policies and strategies, effective January 1, 2012, the expected long term rate of return on plan assets was changed from 8.50 percent to 7.75 percent.

Schedule of Health Care Cost Trend Rates [Table Text Block]

	2011	2010	2009
Health care cost trend rate assumed for the following year:			

Medical			
Pre-65	7.50%	7.50%	7.00%
Post-65	7.00%	7.00%	6.75%
Prescription drugs	7.50%	7.50%	7.50%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):			
Medical			
Pre-65	5.00%	5.00%	5.00%
Post-65	5.00%	5.00%	5.00%
Prescription drugs	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate:			
Medical			
Pre-65	2018	2018	2014
Post-65	2017	2017	2015
Prescription drugs	2018	2018	2015

Schedule of Effect of One-Percentage-Point Change in Assumed Health Care Cost Trend Rates [Table Text Block]

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 2	$ 2
Effect on other postretirement benefit obligations	33	27

Fair Value of Defined Benefit Pension Plans Assets [Table Text Block]

	December 31, 2011							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 12	$ 2	$ -	$ -	$ -	$ -	$ 12	$ 2
Equity securities:								
Investment trusts	-	-	7	-	-	-	7	-
Exchange traded funds	324	-	-	-	-	-	324	-
Private equity	-	-	-	-	23	-	23	-
Investment funds								
Mutual funds - equity {a}	-	159	-	-	-	-	-	159
Pooled funds - equity {b}	-	-	-	96	-	-	-	96
Pooled funds - fixed income {c}	-	-	-	149	-	-	-	149
U.S. treasuries	92	-	-	-	-	-	92	-
Real estate {d}	-	-	-	-	21	-	21	-
Other	-	-	30 {e}	6	7	-	37	6
Total investments, at fair value	$ 428	$ 161	$ 37	$ 251	$ 51	$ -	$ 516 {f}	$ 412

	December 31, 2010							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 8	$ 1	$ -	$ -	$ -	$ -	$ 8	$ 1
Equity securities:								
Investment trusts	25	0	137	-	-	-	162	-
Exchange traded funds	56	0	-	-	-	-	56	-
Private equity	-	-	-	-	67	-	67	-
Investment funds								
Mutual funds - equity {a}	-	161	-	-	-	-	0	161
Pooled funds - equity {b}	-	-	1,072	97	-	-	1,072	97
Pooled funds - fixed income {c}	-	-	350	126	-	-	350 0	126

Real estate [d]	-	-	-	0	54	-	54	-
Other	-	-	5	4	24	-	29	4
Total investments, at fair value	$ 89	$ 162	$ 1,564	$ 227	$ 145	$ 0	$ 1,798	$ 389

(a) Includes approximately 70 percent of investments held in U.S. and non-U.S. common stocks in the financial services, consumer staples, health care, energy and basic material sectors and 30 percent of investments held among various other sectors. The funds objective is to outperform their respective benchmark indexes FTSE All Share, MSCI World Free, and MSCI Europe (excluding the U.K.) as defined by the investment policy.

(b) U.S. – At December 31, 2010, includes approximately 70 percent of investments held in U.S. and non-U.S. publicly traded common stocks in the consumer staples, consumer discretionary, technology, health and energy sectors and 30 percent of investments held among various other sectors. Int'l – Includes approximately 70 percent of investments held in non-U.S. common stocks (specifically Asia Pacific, except Japan, and the U.K.) in the financials, energy, consumer staples, industrials, and telecommunication services sectors and the 30 percent of investments held amongst various other sectors. The funds objective is to outperform their respective benchmark indexes, MSCI AC Asia and FTSE All-Share, as defined by the investment policy.

(c) U.S. – At December 31, 2010, includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include treasuries, mortgage-backed securities and industrials and 20 percent of investments held among various other sectors. Int'l – Includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include gilts, treasuries, financials, sovereigns and collateralized asset backed securities and 20 percent of investments held among various other sectors. The funds objective is to outperform their respective benchmark indexes, as defined by the investment policy.

(d) Includes investments diversified by property type and location. The largest property sector holdings, which represent approximately 70 percent of investments held, are office, hotel, residential and land with the greatest percentage of investments made in the U.S. and Asia, which includes the emerging markets of China and India.

(e) Includes an $18 million receivable for the sale of an investment that closed as of December 31, 2011 but did not cash settle until the next business day.

Schedule of Effect of Significant Unobservable Inputs, Changes in Plan Assets [Table Text Block]

	2011			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 67	$ 54	$ 24	$ 145
Spin-off downstream business	(46)	(37)	(17)	(100)
Actual return on plan assets	3	2	-	5
Purchases	3	4	-	7
Sales	(4)	(2)	-	(6)
Ending balance	$ 23	$ 21	$ 7	$ 51

	2010			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 42	$ 36	$ 23	$ 101
Actual return on plan assets	13	4	1	18
Purchases	15	17	-	32
Sales	(3)	(3)	-	(6)
Ending balance	$ 67	$ 54	$ 24	$ 145

Schedule of Expected Benefit Payments [Table Text Block]

	Pension Benefits		Other
(In millions)	U.S.	Int'l	Benefits [a]
2012	$ 104	$ 12	$ 21
2013	100	13	22
2014	102	15	22
2015	101	16	23
2016	104	18	24
2017 through 2021	482	105	121

(a) Expected Medicare reimbursements for 2012 through 2013 total $5 million. Effective 2013, as a result of the PPACA, future Medicare reimbursements will no longer be tax deductible and must be used to reduce the costs of providing Medicare Part D equivalent prescription drug benefits to retirees. The total of these future reimbursements from 2014 through 2021 is $22 million.

(a) Expected Medicare reimbursements for 2012 through 2013 total \$5 million. Effective 2013, as a result of the PPACA, future Medicare reimbursements will no longer be tax deductible and must be used to reduce the costs of providing Medicare Part D equivalent prescription drug benefits to retirees. The total of these future reimbursements from 2014 through 2021 is \$22 million.

EMI and Related Party (Tables)	12 Months Ended Dec. 31, 2011
Equity Method Investments Note Tables [Abstract]	
Equity Method Investments Table [Text Block]	

(In millions)	Ownership as of December 31, 2011	December 31, 2011	December 31, 2010
EGHoldings	60%	$ 875	$ 927
Alba Plant LLC	52%	272	303
AMPCO	45%	191	210
Downstream business investments		0	311
Other investments		45	51
Total		$ 1,383	$ 1,802

Income And Balance Sheet Information of Equity Investees Table [Text Block]

(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.

Consolidated Balance Sheets Parentheticals (USD $) In Millions, except Share data, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Consolidated Balance Sheets Parenthetical [Abstract]		
Allowance for doubtful accounts	$ 0	$ (7)
Less accumulated depreciation, depletion and amortization	$ (17,248)	$ (19,805)
Preferred stock, no par value	$ 0	$ 0
Preferred stock shares authorized	26,000,000	26,000,000
Preferred stock shares issued	0	0
Preferred stock shares outstanding	0	0
Common stock, par value per share	$ 1	$ 1
Common stock shares authorized	1,100,000,000	1,100,000,000
Common stock, shares issued	770,000,000	770,000,000
Common stock, securities exchangeable, no par value	$ 0	$ 0
Common stock, securities exchangeable, shares authorized	29,000,000	29,000,000
Common stock, securities exchangeable, shares issued	0	0
Common stock, securities exchangeable, shares outstanding	0	0
Held in treasury, shares	66,000,000	60,000,000

Stock-Based Compensation Plans (Details) (USD $) In Millions, except Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Stock Option Disclosure [Abstract]			
Common Stock that may be issued under the 2007 Plan	34		
Portion of shares under 2007 plan that may be used for awards other than stock options or stock appreciation rights	12		
Employee stock based compensation expense	$ 65	$ 51	$ 59
Tax benefits related to stock-based compensation expense	23	19	22
Cash received upon exercise of stock option awards	77	12	4
Tax benefits realized for deductions for stock awards exercised	$ 32	$ 11	$ 10
Schedule of Weighted Average Grant Date Fair Value of Stock Option Awards [Abstract]			
Weighted average exercise price per share	$ 32.30	$ 30.00	$ 27.62
Expected annual dividends per share	2.10%	3.20%	3.50%
Expected life in years	5.3	5.1	4.9
Expected volatility	40.00%	43.00%	41.00%
Risk-free interest rate	1.70%	2.20%	2.30%
Weighted average grant date fair value of stock option awards granted	$ 10.44	$ 8.70	$ 7.67

Spin-Off	12 Months Ended Dec. 31, 2011
Spin Off Disclosure [Abstract]	
Spin Off Disclosure [Text Block]	(see below)

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.

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

Segment Information (Details) (USD $) In Millions, unless otherwise specified	6 Months Ended	12 Months Ended		
	Jun. 30, 2011	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Revenues:				
Customer		$ 14,603	$ 11,634	$ 8,465
Related parties		60	56	59
Total revenue		14,663	11,690	8,524
Segment income		2,591	2,033	1,352
Income (loss) from equity method investments,segment		462	344	268
Depreciation, depletion and amortization, segment		2,266	2,056	1,934
Income tax provision (benefit), segment		2,720	2,175	2,047
Crude oil intersegment sales reclass	1,400		1,800	534
MPC [Member]				
Entity-Wide Revenue, Major Customer, Percent [Line Items]				
Entity-Wide Revenue, Major Customer, Percent		18.00%	16.00%	12.00%
Libyan National Oil Company [Member]				
Entity-Wide Revenue, Major Customer, Percent [Line Items]				
Entity-Wide Revenue, Major Customer, Percent			13.00%	13.00%
Exploration and Production Segment [Member]				
Revenues:				
Customer		12,922	10,651	7,651
Intersegment revenues		47	75	28
Related parties		60	56	59
Segment revenues, total		13,029	10,782	7,738
Elimination of intersegment revenues		(47)	(75)	(28)
Gain on U.K. natural gas contracts				72
Total revenue		12,982	10,707	7,782
Segment income		2,157	1,941	1,218
Income (loss) from equity method investments,segment		249	188	125
Depreciation, depletion and amortization, segment		2,028	1,911	1,776
Income tax provision (benefit), segment		2,808	2,266	1,560
Capital expenditures, segment		3,038	2,474	2,162
Oil Sands Mining Segment [Member]				
Revenues:				
Customer		1,588	833	692
Segment revenues, total		1,588	833	692
Total revenue		1,588	833	692
Segment income		256	(50)	44
Income (loss) from equity method investments,segment			0	
Depreciation, depletion and amortization, segment		196	105	124
Income tax provision (benefit), segment		82	(12)	6

Capital expenditures, segment	308	874	1,115
Integrated Gas Segment [Member]			
Revenues:			
Customer	93	150	50
Segment revenues, total	93	150	50
Total revenue	93	150	50
Segment income	178	142	90
Income (loss) from equity method investments,segment	213	181	143
Depreciation, depletion and amortization, segment	3	2	3
Income tax provision (benefit), segment	74	73	39
Capital expenditures, segment	2	2	2
Total All Segments [Member]			
Revenues:			
Customer	14,603	11,634	8,393
Intersegment revenues	47	75	28
Related parties	60	56	59
Segment revenues, total	14,710	11,765	8,480
Elimination of intersegment revenues	(47)	(75)	(28)
Gain on U.K. natural gas contracts			72
Income (loss) from equity method investments,segment	462	369	268
Depreciation, depletion and amortization, segment	2,227	2,018	1,903
Income tax provision (benefit), segment	2,964	2,327	1,605
Capital expenditures, segment	$ 3,348	$ 3,350	$ 3,279

Defined Benefit Postretirement Plans (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended	
	Dec. 31, 2011	Dec. 31, 2010
Change in benefit obligations:		
Spin-off downstream business	$ (483)	
Benefits paid	(83)	
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]		
Benefits paid	(83)	
Fair value of plan assets at December 31	6	
United States Pension Plans Of US Entity Defined Benefit [Member]		
Change in benefit obligations:		
Benefit obligations at January 1	3,221	2,989
Spin-off downstream business	(2,308)	
Service Cost	28	92
Interest Cost	44	153
Actuarial loss (gain)	84	287
Benefits paid	(83)	(300)
Benefit obligations at December 31	986	3,221
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]		
Fair value of plan assets at January 1	1,798	1,623
Spin-off downstream business	(1,268)	
Actual return on plan assets	30	214
Employer contributions	39	267
Other		(6)
Benefits paid	(83)	(300)
Fair value of plan assets at December 31	516	1,798
Funded status of plans		
Funded status of plans at December 31	(470)	(1,423)
Amounts recognized in the consolidated balance sheet		
Pension current liabilities	(17)	(21)
Pension noncurrent liabilities	(453)	(1,402)
Accrued benefit cost	(470)	(1,423)
Pretax amounts in accumulated other comprehensive income:		
Net loss	432	1,382
Prior service cost (credit)	27	81
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets [Abstract]		
Projected benefit obligation	(986)	(3,221)
Accumulated benefit obligation	(813)	(2,365)
Fair value of plan assets	516	1,798
Foreign Pension Plans Defined Benefit [Member]		
Change in benefit obligations:		

Benefit obligations at January 1	415	395
Service Cost	19	19
Interest Cost	22	22
Plan Amendments	11	
Actuarial loss (gain)	13	6
Foreign currency exchange rate changes on plan obligations	2	18
Other		6
Benefits paid	(13)	(15)
Benefit obligations at December 31	465	415
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]		
Fair value of plan assets at January 1	389	348
Actual return on plan assets	15	47
Employer contributions	23	20
Foreign currency exchange rate changes	2	14
Other		3
Benefits paid	(13)	(15)
Fair value of plan assets at December 31	412	389
Funded status of plans		
Funded status of plans at December 31	(53)	(26)
Amounts recognized in the consolidated balance sheet		
Pension noncurrent liabilities	(53)	(26)
Accrued benefit cost	(53)	(26)
Pretax amounts in accumulated other comprehensive income:		
Net loss	63	41
Prior service cost (credit)	11	
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets [Abstract]		
Projected benefit obligation	(465)	
Accumulated benefit obligation	(418)	
Fair value of plan assets	412	
Other Postretirement Benefit Plans Defined Benefit [Member]		
Change in benefit obligations:		
Benefit obligations at January 1	779	685
Service Cost	4	18
Interest Cost	16	39
Actuarial loss (gain)	1	69
Benefits paid	(16)	(32)
Benefit obligations at December 31	301	779
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]		
Benefits paid	(16)	(32)
Funded status of plans		
Funded status of plans at December 31	(301)	(779)
Amounts recognized in the consolidated balance sheet		
Pension current liabilities	(18)	(36)

Pension noncurrent liabilities	(283)	(743)
Accrued benefit cost	(301)	(779)
Pretax amounts in accumulated other comprehensive income:		
Net loss	16	18
Prior service cost (credit)	$ (18)	$ (24)

Property, Plant and Equipment (Details 2) (USD $) In Millions, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009	Dec. 31, 2008
Total Deferred Exploratory Well Costs [Abstract]				
Amounts capitalized greater than one year after completion of drilling	$ 222	$ 323	$ 150	
Amounts capitalized less than one year after completion of drilling	482	334	679	
Capitalized Exploratory Well Costs, Total	704	657	829	917
Projects that have Exploratory Well Costs that have been Capitalized for Period Greater than One Year, Number of Projects	5	7	3	
GOM Capitalized Greater One Year [Member]				
Total Deferred Exploratory Well Costs [Abstract]				
Amounts capitalized greater than one year after completion of drilling	73			
Angola Capitalized Greater One Year [Member]				
Total Deferred Exploratory Well Costs [Abstract]				
Amounts capitalized greater than one year after completion of drilling	124			
Other International Capitalized Greater One Year [Member]				
Total Deferred Exploratory Well Costs [Abstract]				
Amounts capitalized greater than one year after completion of drilling	$ 25			

Defined Benefit Postretirement Plans	12 Months Ended Dec. 31, 2011
Defined Benefit Postretirement Plans Disclosure [Abstract]	
Defined Benefit Postretirement Plans	

20. Defined Benefit Postretirement Plans

We have noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in Norway and the United Kingdom. Benefits under these plans are based on plan provisions specific to each plan.

We also have defined benefit plans for other postretirement benefits covering most employees. Health care benefits are provided through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Life insurance benefits are provided to certain retiree beneficiaries. Other postretirement benefits are not funded in advance.

Obligations and funded status – The accumulated benefit obligation for all defined benefit pension plans was $1,231 million and $2,737 million as of December 31, 2011 and 2010.

Summary information for our defined benefit pension plans follows. In 2011, both our U.S. and international plans have accumulated benefit obligations in excess of plan assets, while in 2010 only our U.S. plans had accumulated benefit obligations in excess of plan assets.

	December 31,		
	2011		2010
(In millions)	U.S.	Int'l	U.S.
Projected benefit obligation	$ (986)	$ (465)	$ (3,221)
Accumulated benefit obligation	(813)	(418)	(2,365)
Fair value of plan assets	516	412	1,798

The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

	Pension Benefits				Other Benefits	
	2011		2010		2011	2010
(In millions)	U.S.	Int'l	U.S.	Int'l		
Change in benefit obligations:						
Benefit obligations at January 1	$ 3,221	$ 415	$ 2,989	$ 395	$ 779	$ 685
Spin-off downstream business	(2,308)	0	0	0	(483)	0
Service cost	28	19	92	19	4	18
Interest cost	44	22	153	22	16	39
Plan amendment	0	11	0	0	0	0
Actuarial loss	84	13	287	6	1	69
Foreign currency exchange rate changes	0	(2)	0	(18)	0	0
Other	0	0	0	6	0	0
Benefits paid	(83)	(13)	(300)	(15)	(16)	(32)
Benefit obligations at December 31	$ 986	$ 465	$ 3,221	$ 415	$ 301	$ 779
Change in plan assets:						
Fair value of plan assets at January 1	$ 1,798	$ 389	$ 1,623	$ 348	$ 0	$ 0
Spin-off downstream business	(1,268)	0	0	0	0	0
Actual return on plan assets	30	15	214	47	0	0
Employer contributions	39	23	267	20	0	0
Foreign currency exchange rate changes	0	(2)	0	(14)	0	0
Other	0	0	(6)	3	0	0
Benefits paid	(83)	(13)	(300)	(15)	0	0
Fair value of plan assets at December 31	$ 516	$ 412	$ 1,798	$ 389	$ 0	$ 0
Funded status of plans at December 31	$ (470)	$ (53)	$ (1,423)	$ (26)	$ (301)	$ (779)

Amounts recognized in the consolidated						
balance sheet:						
Current liabilities	(17)	0	(21)	0	(18)	(36)
Noncurrent liabilities	(453)	(53)	(1,402)	(26)	(283)	(743)
Accrued benefit cost	$ (470)	$ (53)	$ (1,423)	$ (26)	$ (301)	$ (779)
Pretax amounts in accumulated other						
comprehensive income:						
Net loss	$ 432	$ 63	$ 1,382	$ 41	$ 16	$ 18
Prior service cost (credit)	27	11	81	0	(18)	(24)

Components of net periodic benefit cost and other comprehensive income –The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive income for our defined benefit pension and other postretirement plans.

	Pension Benefits								
	2011		2010		2009		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2011	2010	2009
Components of net periodic benefit cost related to continuing									
operations:									
Service cost	$ 28$	19$	30$	19$	36$	14$	4$	3$	3
Interest cost	44	22	47	22	46	22	16	16	18
Expected return on plan assets	(43)	(23)	(44)	(22)	(47)	(21)	-	-	-
- prior service cost (credit)	6	-	6	-	6	1	(7)	(7)	(6)
- actuarial loss	47	2	48	5	20	2	-	-	-
Other	-	-	-	2	-	-	-	-	-
Net settlement/curtailment loss [a]	30	-	56	-	4	18	-	-	-
Net periodic benefit cost [b]	$ 112$	20$	143$	26$	65$	36$	13$	12$	15
Other changes in plan assets and benefit									
obligations recognized in other									
comprehensive income (pretax):									
Actuarial loss (gain)	$ 97$	24$	211$	(25)$	587$	52$	1$	69$	(34)
Amortization of actuarial (loss) gain	(77)	(2)	(167)	(5)	(33)	(7)	-	2	5
Prior service cost	-	(11)	-	-	-	-	-	-	-
Amortization of prior service credit (cost)	(6)	-	(13)	-	(13)	(1)	7	6	5
Spin off downstream business	(24)	-	-	-	-	-	-	-	-
Total recognized in other comprehensive income	$ (10)$	11$	31$	(30)$	541$	44$	8$	77$	(24)
Total recognized in net periodic benefit cost and									
other comprehensive income	$ 102$	31$	174$	(4)$	606$	80$	21$	89$	(9)

(a) Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. plans in 2011 and 2010. Additionally, in 2009 a curtailment and settlement was recorded related to our discontinued operations in Ireland as discussed in Note 6.

(b) Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

The estimated net loss and prior service cost for our defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2012 are $46 million and $7 million. The estimated prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2012 is $7 million.

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2011, 2010 and 2009.

	Pension Benefits								
	2011		2010		2009		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2011	2010	2009
Weighted average assumptions used to									
determine benefit obligation:									
Discount rate	4.45%	4.70%	5.05%	5.40%	5.50%	5.70%	4.90%	5.55%	5.95%
Rate of compensation increase	5.00%	4.30%	5.00%	5.10%	4.50%	5.55%	5.00%	5.00%	4.50%
Weighted average assumptions used to									
determine net periodic benefit cost:									
Discount rate	5.05%	5.40%	5.23%	5.70%	6.90%	6.70%	5.55%	6.85%	6.85%
Expected long-term return on plan assets {a}	8.50%	5.86%	8.50%	6.40%	8.50%	6.10%	-	-	-
Rate of compensation increase	5.00%	5.10%	4.50%	5.55%	4.50%	4.75%	5.00%	4.50%	4.50%

a. Due to the revised targeted asset allocation as discussed under the plan investment policies and strategies, effective January 1, 2012, the expected long term rate of return on plan assets was changed from 8.50 percent to 7.75 percent.

Expected long-term return on plan assets

U.S. plan – The overall expected long-term return on plan assets assumption for our U.S. plan is determined based on an asset rate-of-return modeling tool developed by a third-party investment group. The tool utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plan's asset allocation to derive an expected long-term rate of return on those assets. Capital market assumptions reflect the long-term capital market outlook. The assumptions for equity and fixed income investments are developed using a building-block approach, reflecting observable inflation information and interest rate information available in the fixed income markets. Long-term assumptions for other asset categories are based on historical results, current market characteristics and the professional judgment of our internal and external investment teams.

International plans – To determine the overall expected long-term return on plan assets assumption for our international plans, we consider the current level of expected returns on risk-free investments (primarily government bonds), the historical levels of the risk premiums associated with the other applicable asset categories and the expectations for future returns of each asset class. The expected return for each asset category is then weighted based on the actual asset allocation in our international pension plans to develop the overall expected long-term return on plan assets assumption.

Assumed health care cost trend rates

	2011	2010	2009
Health care cost trend rate assumed for the following year:			
Medical			
Pre-65	7.50%	7.50%	7.00%
Post-65	7.00%	7.00%	6.75%
Prescription drugs	7.50%	7.50%	7.50%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):			
Medical			
Pre-65	5.00%	5.00%	5.00%
Post-65	5.00%	5.00%	5.00%
Prescription drugs	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate:			
Medical			
Pre-65	2018	2018	2014
Post-65	2017	2017	2015
Prescription drugs	2018	2018	2015

Assumed health care cost trend rates have a significant effect on the amounts reported for defined benefit retiree health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-	1-Percentage-

(In millions)		Point Increase	Point Decrease
Effect on total of service and interest cost components	$	2$	2
Effect on other postretirement benefit obligations		33	27

Plan investment policies and strategies

The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with the legal requirements of all applicable laws; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plans' investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation.

U.S. plan – Historical performance and future expectations suggest that common stocks will provide higher total investment returns than fixed income securities over a long-term investment horizon. Short-term investments are utilized for pension payments, expenses, and other liquidity needs. As such, for 2011 and prior, the plan's targeted asset allocation was comprised of 75 percent equity securities and 25 percent fixed income securities. Effective January 1, 2012, the U.S. plan's targeted asset allocation is comprised of 65 percent equity securities and 35 percent fixed income securities but may be adjusted accordingly to better match the plan's liabilities over time as the funded ratio (as defined by the investment policy) changes.

The plan's assets are managed by a third-party investment manager. The investment manager is limited to pursuing the investment strategies regarding asset mix and purchases and sales of securities within the parameters defined in the investment policy guidelines and investment management agreement. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

International plans – Our international plans' target asset allocation is comprised of 70 percent equity securities and 30 percent fixed income securities. The plan assets are invested in six separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers. Investments are diversified by industry and type, limited by grade and maturity. The use of derivatives by the investment managers is permitted, subject to strict guidelines. The investment managers' performance is measured independently by a third-party asset servicing consulting firm. Overall, investment performance and risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and periodic asset and liability studies.

Fair value measurements

Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2011 and 2010.

Cash and cash equivalents – Cash and cash equivalents include cash on deposit and an investment in a money market mutual fund that invests mainly in short-term instruments and cash, both of which are valued using a market approach and are considered Level 1 in the fair value hierarchy. The money market mutual fund is valued at the net asset value ("NAV") of shares held.

Equity securities – Investments in public investment trusts and S&P 500 exchange-traded funds are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. During the fourth quarter 2011, Level 1 investment trust holdings were liquidated and the proceeds were re-invested in an exchange traded fund. Non-public investment trusts are valued using a market approach based on the underlying investments in the trust, which are publicly-traded securities, and are considered Level 2. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership, determined using a combination of market, income and cost approaches, plus working capital, adjusted for liabilities, currency translation and estimated performance incentives. These private equity investments are considered Level 3.

Mutual funds – Investments in mutual funds are valued using a market approach. The shares or units held are traded on the public exchanges and such prices are Level 1 inputs.

Pooled funds – Investments in pooled funds are valued using a market approach at the NAV of units held, but investment opportunities in such funds are limited to institutional investors on the behalf of defined benefit plans. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. During the fourth quarter 2011, the U.S. plan's ownership interest held in the fixed income pooled fund was liquidated and the proceeds were re-invested in U.S. treasuries. Further, the U.S. plan's ownership interest held in the equity based pooled fund was liquidated and the proceeds were re-invested in an exchange traded fund. The majority of the pooled funds held by our international pension plans are benchmarked against a relative public index. These are considered Level 2.

U.S. treasuries – U.S. treasury notes are valued at the closing price reported in an active market. These notes are considered Level 1 investments.

Real estate – Real estate investments are valued based on discounted cash flows, comparable sales, outside appraisals, price per square foot or some combination thereof and therefore are considered Level 3.

Other – Other investments are composed of an investment in an unallocated annuity contract, an investment contract with an international insurance carrier, and investments in two limited liability companies ("LLCs") with no public market. The LLCs were formed to acquire timberland in the northwest and other properties. The investment in an unallocated annuity contract is valued using a market approach based on the experience of the assets held in an insurer's general account and is considered Level 2. The majority of the general account is invested in a well-diversified portfolio of high-quality fixed income securities, primarily consisting of investment-grade bonds. Investment income is allocated among pension plans participating in the general account based on the investment year method. Under this method, a record of the book value of assets held is maintained in subdivisions according to the calendar year in which the funds are invested. The earnings rate for each of these calendar year subdivisions varies from year to year, reflecting the actual earnings on the assets attributed to that year. The insurance carrier contract is funded by premiums paid annually by the participating plans and the funds are invested by the insurance carrier in portfolios with different risk profiles (low, medium, high) that can be elected by investors. The contract is valued using a market approach based on the underlying investments within the portfolio and is considered Level 2. The majority of the underlying investments consists of a well-diversified mix of non-U.S. publicly traded equity and fixed income securities. The values of the LLCs are determined using an income approach based on discounted cash flows and are considered Level 3.

The following table presents the fair values of our defined benefit pension plans' assets, by level within the fair value hierarchy, as of December 31, 2011 and 2010.

	December 31, 2011							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 12	$ 2	$ -	$ -	$ -	$ -	$ 12	$ 2
Equity securities:								
Investment trusts	-	-	7	-	-	-	7	-
Exchange traded funds	324	-	-	-	-	-	324	-
Private equity	-	-	-	-	23	-	23	-
Investment funds								
Mutual funds - equity [a]	-	159	-	-	-	-	-	159
Pooled funds - equity [b]	-	-	-	96	-	-	-	96
Pooled funds - fixed income [c]	-	-	-	149	-	-	-	149
U.S. treasuries	92	-	-	-	-	-	92	-
Real estate [d]	-	-	-	-	21	-	21	-
Other	-	-	30 [e]	6	7	-	37	6
Total investments, at fair value	$ 428	$ 161	$ 37	$ 251	$ 51	$ -	$ 516 [f]	$ 412

	December 31, 2010							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 8	$ 1	$ -	$ -	$ -	$ -	$ 8	$ 1
Equity securities:								
Investment trusts	25	0	137	-	-	-	162	-
Exchange traded funds	56	0	-	-	-	-	56	-
Private equity	-	-	-	-	67	-	67	-
Investment funds								
Mutual funds - equity [a]	-	161	-	-	-	-	0	161
Pooled funds - equity [b]	-	-	1,072	97	-	-	1,072	97
Pooled funds - fixed income [c]	-	-	350	126	-	-	350 0	126
Real estate [d]	-	-	-	0	54	-	54	-
Other	-	-	5	4	24	-	29	4
Total investments, at fair value	$ 89	$ 162	$ 1,564	$ 227	$ 145	$ 0	$ 1,798	$ 389

(a) Includes approximately 70 percent of investments held in U.S. and non-U.S. common stocks in the financial services, consumer staples, health care, energy and basic material sectors and 30 percent of investments held among various other sectors. The funds objective is to outperform their respective benchmark indexes FTSE All Share, MSCI World Free, and MSCI Europe (excluding the U.K.) as defined by the investment policy.

(b) U.S. – At December 31, 2010, includes approximately 70 percent of investments held in U.S. and non-U.S. publicly traded common stocks in the consumer staples, consumer discretionary, technology, health and energy sectors and 30 percent of investments held among various other sectors. Int'l – Includes approximately 70 percent of investments held in non-U.S. common stocks (specifically Asia Pacific, except Japan, and the U.K.) in the financials, energy, consumer staples, industrials, and telecommunication services sectors and the 30 percent of investments held amongst various other sectors. The funds objective is to outperform their respective benchmark indexes, MSCI AC Asia and FTSE All-Share, as defined by the investment policy.

(c) U.S. – At December 31, 2010, includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include treasuries, mortgage-backed securities and industrials and 20 percent of investments held among various other sectors. Int'l – Includes approximately 80 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include gilts, treasuries, financials, sovereigns and collateralized asset backed securities and 20 percent of investments held among various other sectors. The funds objective is to outperform their respective benchmark indexes, as defined by the investment policy.

(d) Includes investments diversified by property type and location. The largest property sector holdings, which represent approximately 70 percent of investments held, are office, hotel, residential and land with the greatest percentage of investments made in the U.S. and Asia, which includes the emerging markets of China and India.

(e) Includes an $18 million receivable for the sale of an investment that closed as of December 31, 2011 but did not cash settle until the next business day.

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

	2011			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 67	$ 54	$ 24	$ 145
Spin-off downstream business	(46)	(37)	(17)	(100)
Actual return on plan assets	3	2	-	5
Purchases	3	4	-	7
Sales	(4)	(2)	-	(6)
Ending balance	$ 23	$ 21	$ 7	$ 51

	2010			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$ 42	$ 36	$ 23	$ 101
Actual return on plan assets	13	4	1	18
Purchases	15	17	-	32
Sales	(3)	(3)	-	(6)
Ending balance	$ 67	$ 54	$ 24	$ 145

Cash flows

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $113 million in 2012. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $18 million and $21 million in 2012.

Estimated future benefit payments – The following gross benefit payments, which reflect expected future services, as appropriate, are expected to be paid in the years indicated.

	Pension Benefits		Other
(In millions)	U.S.	Int'l	Benefits [a]
2012	$ 104	$ 12	$ 21
2013	100	13	22
2014	102	15	22
2015	101	16	23
2016	104	18	24

2017 through 2021	482	105	121

a) Expected Medicare reimbursements for 2012 through 2013 total $5 million. Effective 2013, as a result of the PPACA, future Medicare reimbursements will no longer be tax deductible and must be used to reduce the costs of providing Medicare Part D equivalent prescription drug benefits to retirees. The total of these future reimbursements from 2014 through 2021 is $22 million.

Contributions to defined contribution plans – We contribute to several defined contribution plans for eligible employees. Contributions to these plans related to continuing operations totaled $50 million in 2011, $75 million in 2010 and $59 million in 2009.

Fair Value Measurements (Details 3-Reported) (USD $) In Millions, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Fair Value [Member]		
Financial Instruments, Financial Assets, Balance Sheet Groupings [Abstract]		
Other current financial assets	$ 146	$ 226
Other noncurrent financial assets	68	396
Total financial assets	214	622
Financial liabilities		
Long-term Debt, Fair Value	5,479	8,364
Deferred credits and other financial liabilities	36	66
Total financial liabilities	5,515	8,430
Carrying Amount [Member]		
Financial Instruments, Financial Assets, Balance Sheet Groupings [Abstract]		
Other current financial assets	148	220
Other noncurrent financial assets	68	231
Total financial assets	216	451
Financial liabilities		
Long-term Debt, Fair Value	4,753	7,527
Deferred credits and other financial liabilities	38	67
Total financial liabilities	$ 4,791	$ 7,594

Other Items (Tables)

	12 Months Ended Dec. 31, 2011

Other Income and Expenses [Abstract]

Schedule Of Net Interest And Other Financing Table [Text Block]

(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

Schedule Of Foreign Currency Transactions Table [Text Block]

(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)

Property, Plant and Equipment	12 Months Ended Dec. 31, 2011
Property Plant And Equipment Disclosure [Abstract]	
Property, Plant and Equipment	**13. Property, Plant and Equipment**

(In millions)	December 31, 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

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:

(In millions)	December 31, 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.