MARATHON OIL CORP
Form 10-K
February 28, 2014

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, 2013
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

Securities registered pursuant to Section 12(g) of the Act: None

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

The aggregate market value of Common Stock held by non-affiliates as of June 28, 2013: $24,462 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 696,944,638 shares of Marathon Oil Corporation Common Stock outstanding as of January 31, 2014.

Documents Incorporated By Reference:

Portions of the registrant's proxy statement relating to its 2014 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).

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Definitions

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

AECO – Alberta Energy Company, a Canadian natural gas benchmark price.

AMPCO – Atlantic Methanol Production Company LLC, a company located in Equatorial Guinea 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 United States gallons liquid volume.

bbld – Barrels per day.

bboe – Billion barrels of oil equivalent. Natural gas is converted to a barrel of oil equivalent based on the energy equivalent, which on a dry gas basis is six thousand cubic feet 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 equivalence 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 on 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.

E.G. – Equatorial Guinea.

EGHoldings – Equatorial Guinea LNG Holdings Limited, a liquefied natural gas production company located in E.G. in which we own a 60 percent equity interest.

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 natural gas in an unproved area or find a new reservoir in a field previously found to be productive in another reservoir.

FASB – Financial Accounting Standards Board.

FPSO – Floating production, storage and offloading vessel.

IFRS – International Financial Reporting Standards.

Internal Losses – Production losses attributed to factors that are within our control which can be either planned, such as a planned turnaround, or unplanned, such as equipment failure.

International E&P – Our International Exploration and Production ("Int'l E&P") segment which explores for, produces and markets liquid hydrocarbons and natural gas outside of North America and produces and markets products manufactured from natural gas, such as liquefied natural gas and methanol, in E.G.

IRS – United States Internal Revenue Service.

KRG – Kurdistan Regional Government.

LNG – Liquefied natural gas.

LPG – Liquefied petroleum gas.

Light sweet crude - A crude oil with an American Petroleum Institute ("API") gravity of 38 degrees or more and a sulfur content of less than 0.5 percent.
Liquid hydrocarbons or liquids – Collectively, crude oil, condensate and natural gas liquids.
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 of 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.
mmta – Million metric tonnes per annum.
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.
NGL or NGLs – Natural gas liquid or natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline, that can be collectively removed from produced natural gas, separated into these substances and sold.
North America E&P ("N.A. E&P") – Our North America Exploration and Production segment which explores for, produces and markets liquid hydrocarbons and natural gas in North America.
OECD – Organization for Economic Cooperation and Development.
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.
Operational Availability – A term used to measure the ability of an asset to produce to its maximum capacity over a specified period of time. This measurement considers Internal Losses that are within our control.
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 liquid hydrocarbon, natural gas and synthetic crude oil reserves are those quantities of liquid hydrocarbons, 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 for 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 liquid hydrocarbons, natural gas and synthetic crude oil 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 – United Kingdom Scottish Area Gas Evacuation system composed of a pipeline and processing terminal.
SAR or SARs – Stock appreciation right or stock appreciation rights.
SCOOP – South Central Oklahoma Oil Province.
SEC – United States 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 and 4-D factors in changes that occurred over time).
Total depth ("TD") – The bottom of a drilled hole, where drilling is stopped, logs are run and casing is cemented.
Total proved reserves – The summation of proved developed reserves and proved undeveloped reserves.
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.
WCS – Western Canadian Select, an oil index benchmark price.
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 sometimes burdened by overriding royalty interest or other interests.
WTI – West Texas Intermediate crude oil, an oil index benchmark 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 Annual Report on Form 10-K may include, but are not limited to statements that relate to (or statements that are subject to risks, contingencies or uncertainties that relate to): levels of revenues, income from operations, net income or earnings per share; levels of liquidity and the availability of financing options; budgets or levels of capital, exploration, environmental, construction or maintenance expenditures; the success or timing of completion of ongoing or anticipated capital, exploration, construction 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; quantitative or qualitative factors about market risk; the potential effect of judicial proceedings on our business and financial condition; levels of common share repurchases; the impact of government legislation and budgetary and tax measures; and the anticipated effects of actions of third parties such as competitors, or federal, foreign, state or local governments and regulatory authorities.

PART I

Item 1. Business

General

Marathon Oil Corporation was incorporated in 2001 and is an international energy company engaged in the exploration, production and marketing of liquid hydrocarbons and natural gas, production and marketing of products manufactured from natural gas and oil sands mining with operations in the U.S., Angola, Canada, E.G., Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq, Libya, Norway and the U.K. We are based in Houston, Texas with our corporate headquarters at 5555 San Felipe Street, 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 stockholders 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. 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 for all periods prior to the spin-off with additional information in Item 8. Financial Statements and Supplementary Data - Note 3 to the consolidated financial statements.

Strategy and Results Summary

Our strategic imperatives are:

- Uncompromising focus on core values to protect our license to operate and drive business performance
- Investment in our people to grow and maintain our capabilities and competencies to ensure shareholders access to the full global opportunity set
- Relentless pursuit of operational and capital efficiency and recognition as the partner / operator of choice
- Acceleration of resource development to optimize value, grow profitable volumes and replace reserves
- Rigorous portfolio management integrated with robust capital allocation
- Quality resource capture through a focused exploration program and opportunistic business development
- Competitive shareholder value through disciplined long-term focus

We continue to focus on liquid hydrocarbon reserves and production worldwide, realizing significant increases in our three key unconventional liquids-rich plays in 2013: the Eagle Ford, Bakken and Oklahoma resource basins. In 2014, approximately 60 percent of our capital, investment and exploration spending budget is allocated to these areas and includes co-development of adjacent formations in parallel with the main horizons. Our exploration program includes prospects in E.G., Ethiopia, Gabon, the Gulf of Mexico, Kenya and the Kurdistan Region of Iraq.

We ended 2013 with proved reserves of approximately 2.2 bboe, an 8 percent increase over 2012. Proved reserve replacement was 194 percent, excluding dispositions.

During 2013, our cash additions to property, plant and equipment were $5.0 billion, including those related to discontinued operations, and we made acquisitions of $74 million. We expect continued spending, primarily funded with cash flow from operations or portfolio optimization, in exploration and development activities in order to realize continued reserve and sales volume growth. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Outlook, for discussion of our $5.9 billion capital, investment and exploration spending budget for 2014.

We continually evaluate ways to optimize our portfolio through acquisitions and divestitures and have exceeded our previously stated goal of divesting between $1.5 billion and $3.0 billion of assets over the period of 2011 through 2013, by closing or entering into agreements for approximately $3.5 billion in divestitures, of which $2.1 billion is from the sales of our Angola assets. The sale of our interest in Angola Block 31 closed in February 2014 and the sale of our interest in Angola Block 32 is expected to close in the first quarter of 2014. Additionally, in December 2013, we commenced efforts to market our assets in the North Sea, both in the U.K. and Norway, which would simplify and concentrate our portfolio to higher margin growth opportunities and increase our production growth rate.

The above discussion of strategy and results includes forward-looking statements with respect to the sale of our interest in Angola Block 32, the possible sale of our U.K. and Norway assets and projected spending and expected investment in exploration and development activities under the 2014 capital, investment and exploration budget. Some factors that could potentially affect the expected investment in exploration and development activities include changes in prices of and demand for liquid hydrocarbons, natural gas and synthetic crude oil, actions of competitors, occurrence of acquisitions or dispositions of oil and natural gas properties, future financial conditions, operating results and economic and/or regulatory factors affecting our businesses. The timing of closing the sale of our interest in Angola Block 32 is subject to customary closing conditions. The possible sale of our U.K. and Norway assets is subject to the identification of one or more buyers, successful negotiations, board approval and execution of definitive agreements. The projected spending under the 2014 capital, investment and exploration spending budget is a good faith estimate, 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.

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.

In the discussion that follows regarding our North America E&P, International E&P and Oil Sands Mining segments, references to net wells, acres, sales or investment indicate our ownership interest or share, as the context requires.

North America E&P Segment

We are engaged in oil and gas exploration, development and/or production activities in the U.S. and Canada.

Unconventional Resource Plays

Eagle Ford - As of December 31, 2013, we had approximately 211,000 net acres in the Eagle Ford in south Texas and 655 gross (493 net) operated producing wells in the Eagle Ford, Austin Chalk and Pearsall formations. With approximately 90 percent pad drilling in 2013, we continued to improve efficiencies and reduce development costs per well. The average spud-to-TD time per well decreased to 13 days during the last quarter of the year compared to 15 days in the same period of 2012. We reached TD on 299 gross operated wells and brought 307 gross operated wells to sales in 2013.

Throughout 2013, we evaluated the potential of downspacing to 40-acre and 60-acre spacing with several pilot programs. Overall, wells drilled in these programs at closer spacing showed improved completion efficiency which helped offset impacts due to tighter well spacing. Continued focus on stimulation design contributed to incremental improvements in well performance across our area of activity. Approximately 39 percent of our 2014 capital, investment and exploration budget is dedicated to the Eagle Ford. Our accelerated drilling plans include drilling 250 - 260 net wells (385 - 405 gross, of which we will operate 340 - 355) in 2014, an increase of almost 20 percent over 2013.

Eagle Ford average net sales for 2013 were 81 mboed, composed of 51 mbbld of crude oil and condensate, 14 mbbld of NGLs and 94 mmcfd of natural gas, compared to 34 mboed in 2012, a 136 percent increase. Our 2013 exit rate was over 98 mboed, a 50 percent increase over December 2012. In 2013, we were able to transport approximately 70 percent of our Eagle Ford production by pipeline. We anticipate the volume of oil sold into pipelines will remain high, with the actual volume fluctuating from quarter to quarter as additional infrastructure to service the area is constructed and commensurate commitments for transportation are executed. The ability to transport more barrels by pipeline enables us to reduce costs, improve reliability and lessen our environmental footprint.

Evaluation of the Austin Chalk and Pearsall formations across our Eagle Ford acreage position in south Texas included four Austin Chalk wells and one well in the Pearsall formation in 2013. Early Austin Chalk production results suggest that the mix of crude oil and condensate, NGLs and natural gas is similar to Eagle Ford condensate wells. We plan to drill 5 to 12 additional gross wells in the Austin Chalk and Pearsall formations in 2014. We will continue to evaluate the Pearsall formation in 2014. Ongoing Austin Chalk and Eagle Ford co-development is planned, pending results from our early wells. Co-development will leverage the infrastructure investments we have made to support production growth across the Eagle Ford operating area.

Approximately 193 miles of gathering lines were installed in 2013 for a total of over 700 miles of operated gathering pipeline in the area. We now have 24 central gathering and treating facilities, with aggregate capacity of over 275 mboed. We also own and operate the Sugarloaf gathering system, a 37-mile natural gas pipeline through the heart of our acreage in Karnes, Atascosa, and Bee Counties of south Texas.

Bakken – We hold approximately 370,000 net acres in the Bakken shale oil play in North Dakota and eastern Montana, where we have been operating since 2006. Since inception, we have continuously sought improvement in efficiency and well performance through optimizing completion techniques. Our average time to drill a well continued to improve, averaging 15 days spud-to-TD in the last quarter of 2013, compared to 18 days in the same period of 2012. We have identified additional improvements to the 30-stage hydraulic fracturing designs put in place in 2012, which are expected to further increase both production rates and estimated ultimate recovery from our Bakken shale wells beyond the increases that were attained in 2012 and 2013. We reached TD on 76 gross operated wells and brought to sales 77 gross operated wells in 2013. Our Bakken shale program includes plans to drill 80 - 90 net wells (200 - 220 gross, of which we will operate 75 - 85) in 2014. In addition, we plan to recomplete 22 - 26 gross wells to the stage design optimized in 2013.

Our net sales from the Bakken shale averaged 39 mboed in 2013, composed of 35 mbbld of crude oil and condensate, 2 mbbld of NGLs and 13 mmcfd of natural gas, a 34 percent increase over 29 mboed in 2012. Our production exit rate for 2013 was approximately 38 mboed. We sell our Bakken production primarily into local North Dakota markets via truck or pipeline in efforts to optimize price realizations and such production could be transported to other areas of the U.S. by the purchaser.

Oklahoma resource basins – We hold 209,000 net acres in unconventional Oklahoma resource basins, namely the Anadarko Woodford shale (including the SCOOP), the Southern Mississippi Trend, and the Granite Wash, of which approximately 147,000 net acres are held by production. We continued to add incremental acres to our SCOOP position in 2013. In the Anadarko Woodford shale, we reached TD on 10 gross operated wells and brought nine gross operated wells to sales in 2013. An additional four net non-operated Woodford wells were brought to sales. We spud three additional operated Woodford wells in the SCOOP near the end of the year. We drilled two gross operated wells in the Southern Mississippi Trend and brought both wells to sales in the fourth quarter of 2013. We also participated in two gross non-operated Southern Mississippi Trend wells in 2013. Lastly, we spud our first operated well in the unconventional Granite Wash play near the end of 2013.

Sales from our Oklahoma resource basin plays in 2013 were primarily from the Anadarko Woodford shale and averaged 14 mboed, composed of 2 mbbld of crude oil and condensate, 4 mbbld of NGLs and 48 mmcfd of natural gas, for an increase of 68 percent over 2012 net sales of 8 mboed. Our accelerated drilling plans for the Oklahoma resource basins include drilling and completing 14 - 20 net (21 - 27 gross) operated wells in 2014, approximately double our 2013 program. Approximately six net non-operated wells are also expected to be completed.

See below for discussion of our conventional, primarily natural gas, production operations in Oklahoma.

Other United States

Gulf of Mexico – Production – On December 31, 2013, we held significant interests in 11 producing fields, 4 of which are company-operated. Average net sales for 2013 from the Gulf of Mexico were 17 mbbld of liquid hydrocarbons and 14 mmcfd of natural gas. Operational availability for our operated properties was strong at 97 percent, with internal unplanned losses of three percent.

We have a 65 percent operated working interest in the Ewing Bank Block 873 platform which is located 130 miles south of New Orleans, Louisiana. The platform 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 have a 100 percent operated working interest in the Droshky development located on Green Canyon Block 244 and a 68 percent operated working interest in Ozona which is located on Garden Banks Block 515. The Ozona development ceased production in the first quarter of 2013 and is scheduled for abandonment in 2014.
We have a 50 percent working interest in the non-operated Petronius field on Viosca Knoll Blocks 786 and 830, located 130 miles southeast of New Orleans, which includes 14 producing wells. The Petronius platform is also capable of providing processing and transportation services to nearby third-party fields. A well side track project was successfully completed in 2013 and a similar project is planned for 2014.
We hold a 30 percent working interest in the non-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. A well side track project is planned for 2014.
We have an 18 percent working interest in the non-operated Gunflint field development located on Mississippi Canyon Blocks 948, 949, 992(N/2) and 993(N/2). The discovery well was drilled in 2008 and encountered pay in the Middle Miocene reservoirs. Two subsequent appraisal wells were drilled and evaluated in 2012 and 2013. First oil from this subsea tie-back development project is expected in 2016.
Gulf of Mexico – Exploration – We have a portfolio of over 17 prospects with multiple drilling opportunities in the Gulf of Mexico. As we evaluate these opportunities for drilling, we plan to seek partners to reduce our exploration risk on individual projects.
We have a 60 percent operated working interest in the Key Largo prospect located on Walker Ridge Block 578. The Key Largo prospect will be the first well drilled with a new ultra deep-water drillship for which we and another operator have recently secured a three-year contract. Drilling is expected to commence in the third quarter of 2014.
Prior to commencing drilling in September 2013, we reduced our working interest in the Madagascar prospect, located on De Soto Canyon Block 757, from 100 percent to 40 percent as a result of two farm-outs, which included drilling cost carries. Our operated exploration well on the Madagascar prospect did not encounter commercial hydrocarbons and the well costs and related unproved property were charged to exploration expense in 2013.
A deepwater oil discovery on the Shenandoah prospect, located on Walker Ridge Block 52, was drilled in 2009. We own a 10 percent non-operated working interest in this prospect. The first appraisal well on the Shenandoah prospect reached total depth in 2013. This appraisal well encountered more than 1,000 net feet of oil pay in multiple high-quality Lower Tertiary-aged reservoirs. Additional appraisal drilling is anticipated to begin in 2014.
In 2013, we were awarded 100 percent working interest leases in two Gulf of Mexico blocks: Keathley Canyon Block 153, an extension to the Meteor prospect on our existing Keathley Canyon Block 196 lease, and Keathley Canyon Block 340 on the Colonial prospect. Both of these blocks are inboard-Paleogene prospects.
Colorado – We hold leases with natural gas production in the Piceance Basin of Colorado, located in the Greater Grand Valley field complex, and held 154,000 net acres in the Niobrara shale located in the DJ Basin that were sold in June 2013. Net sales from Colorado averaged 2 mboed in 2013. We have no plans for operated drilling in Colorado in 2014.
Oklahoma – We have long-established operated and non-operated conventional production in several Oklahoma fields from which 2013 sales averaged 1 mbbld of liquid hydrocarbons and 43 mmcfd of natural gas. In 2013, we participated in seven gross non-operated wells in the state.
Texas/North Louisiana/New Mexico – We hold 268,000 net acres in these areas of which 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 three gross non-operated wells in the Haynesville shale play during 2013. Conventional production was primarily from the Mimms Creek, Pearwood and Oletha fields in 2013, with net sales averaging 5 mboed.
We also participate in several non-operated Permian Basin fields in west Texas and New Mexico. Net sales from this area averaged 7 mboed in 2013. We plan continued carbon dioxide flood programs in the Seminole and Vacuum fields during 2014.
Wyoming – We have ongoing enhanced oil recovery waterflood projects at the mature Bighorn Basin and Wind River Basin fields and at our 100 percent owned and operated Pitchfork field. We have conventional natural gas operations in the Greater Green River Basin and unconventional coal bed natural gas operations in the Powder River Basin. As of December 31, 2013, we had plugged and abandoned 376 of the total 600 wells in the Powder River Basin and expect

production to cease in March 2014 as we wind down those operations.

Our Wyoming net sales averaged 16 mbbld of liquid hydrocarbons and 48 mmcfd of natural gas during 2013. We drilled 2 gross operated development wells in Wyoming in 2013 and plan to drill 10 gross operated wells in 2014. 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.

Canada

We hold interests in both operated and non-operated exploration stage oil sand leases in Alberta, Canada, which would be developed using in-situ methods of extraction. These leases cover approximately 142,000 gross (54,000 net) acres in four project areas: Namur, in which we hold a 70 percent operated interest; Birchwood, in which we hold a 100 percent operated interest; Ells River, in which we hold a 20 percent non-operated interest; and Saleski in which we hold a 33 percent non-operated interest.

During the first quarter of 2012, we submitted a regulatory application relating to our Canada in-situ assets at Birchwood, for a proposed 12 mbbld steam assisted gravity drainage ("SAGD") demonstration project. We expect to receive regulatory approval for this project by the end of 2014. Upon receiving this approval, we will further evaluate our development plans.

Acquisitions and Dispositions

In July 2013, we acquired 4,800 net undeveloped acres in the core of the Eagle Ford shale in a transaction valued at $97 million, including carried interest of $23 million.

In June 2013, we closed the sale of our interests in the DJ Basin for proceeds of $19 million. A pretax loss of $114 million was recorded in the second quarter of 2013.

In February 2013, we closed the sale of our interest in the Neptune gas plant, located onshore Louisiana, for proceeds of $166 million. A $98 million pretax gain was recorded in the first quarter of 2013.

In February 2013, we conveyed our interests in the Marcellus natural gas shale play to the operator. A $43 million pretax loss on this transaction was recorded in the first quarter of 2013.

In January 2013, we closed the sale of our remaining assets in Alaska, for proceeds of $195 million. A pretax gain of $55 million was recorded in 2013.

The above discussions include forward-looking statements with respect to accelerated rig and drilling activity in the Eagle Ford, Bakken, and Oklahoma resource basins, possible increased recoverable resources from improvements to the 30-stage hydraulic fracturing designs in the Bakken resource play, infrastructure improvements in the Eagle Ford resource play, potential development plans for the Austin Chalk and Pearsall formations in the Eagle Ford resource play and for the Petronius and Neptune fields in the Gulf of Mexico, anticipated future exploratory and development drilling activity, projected spending under the 2014 capital, investment and exploration spending budget, planned use of carbon dioxide flood programs, the abandonment of the Powder River Basin in Wyoming, the abandonment of the Ozona development in the Gulf of Mexico, the timing of first oil from the Gunflint development in the Gulf of Mexico, and the timing of project sanction for the the SAGD project. The average times to drill a well may not be indicative of future drilling times. Current production rates may not be indicative of future production rates. Some factors which could possibly affect these forward-looking statements include pricing, supply and demand for liquid hydrocarbons and natural gas, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, availability of materials and labor, other risks associated with construction projects, the inability to obtain or delay in obtaining necessary government and third-party approvals and permits, 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 projected spending under the 2014 capital, investment and exploration spending budget is a good faith estimate, and therefore, subject to change. The SAGD project may further be affected by board approval and transportation logistics. 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 difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

International E&P Segment

We are engaged in oil and gas exploration, development and/or production activities in Angola, E.G., Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq, Libya, Norway, and the U.K. We also include the results of our natural gas liquefaction operations and methanol production operations in E.G. in our International E&P segment.

Africa

Equatorial Guinea – Production – We own a 63 percent operated working interest under a PSC in the Alba field which is offshore E.G. During 2013, E.G. net liquid hydrocarbon sales averaged 34 mbbld and net natural gas sales averaged 442 mmcfd. Operational availability from our company-operated facilities continues to be excellent and averaged 99 percent in 2013, with internal unplanned losses of one percent. A compression project designed to maintain the production plateau two additional years and extend field life up to six years is underway and is expected to be operational in mid-2016.

Dry natural gas from the Alba field, which remains after the condensate and LPG are removed by Alba Plant LLC, as discussed below, is supplied to AMPCO and EGHoldings under long-term contracts at fixed prices. Because of the location and limited local demand for natural gas in E.G., we consider the prices under the contracts with Alba Plant LLC, EGHoldings and AMPCO to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances. Any dry gas not sold is returned offshore and reinjected into the Alba field for later production.

Equatorial Guinea – Exploration – We hold a 63 percent operated working interest in the Deep Luba discovery on the Alba Block and an 80 percent operated working interest in the Corona well on Block D. We plan to develop Block D through a unitization with the Alba field, which is currently being negotiated. We also have an 80 percent operated working interest in exploratory Block A-12 offshore Bioko Island, located immediately west of our operated Alba Field. We have secured a rig to drill at least two exploration prospects and one Alba field infill well in 2014.

Equatorial Guinea – Gas Processing – We 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 some of the remaining dry natural gas in its operations. During 2013, the gross quantity of natural gas supplied to the LPG production facility was 866 mmcfd, from which 6 mbbld of secondary condensate and 21 mbbld of LPG were produced by Alba Plant LLC.

We also own 60 percent of EGHoldings and 45 percent of AMPCO, both of which are accounted for as equity method investments. EGHoldings operates an LNG production facility and AMPCO operates a methanol plant, both located on Bioko Island. These facilities allow us to monetize natural gas reserves from the Alba field.

EGHoldings' 3.7 mmta LNG production facility sells LNG under a 3.4 mmta, or 460 mmcfd, sales and purchase agreement through 2023. 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. Gross sales of LNG from this production facility totaled 3.98 mmta in 2013. Operational availability was 97 percent in 2013, including a planned turnaround, while internal unplanned losses were less than one percent.

AMPCO had gross sales totaling 1.01 mmt in 2013. Operational availability for this methanol plant was 90 percent in 2013 and internal unplanned losses were 10 percent. Production from the plant is used to supply customers in Europe and the U.S.

Libya – We hold a 16 percent non-operated working interest in the Waha concessions, which encompass almost 13 million acres located in the Sirte Basin of eastern Libya. Beginning in the third quarter of 2013, our Libya production operations were impacted by third-party labor strikes at the Es Sider oil terminal. We have had no oil liftings since July 2013. Uncertainty around production and sales levels from Libya have existed since the first quarter of 2011 when production operations were suspended until the fourth quarter of that year. We and our partners in the Waha concessions continue to assess the situation and the condition of our assets in Libya.

Angola – During 2013, we entered into agreements to sell our Angola assets. See discussion of the transactions in the Acquisitions and Dispositions section below.

Gabon – We hold a 21.25 percent non-operated working interest in the Diaba License G4-223 and its related permit offshore Gabon, which covers 2.2 million gross (476,000 net) acres. The Diaman-1B well reached total depth in the third quarter of 2013, encountering 160-180 net feet of hydrocarbon pay in the deepwater pre-salt play. Preliminary analysis suggests that the hydrocarbons are natural gas with condensate content, pending results of ongoing analysis of well data. Multiple additional pre-salt prospects have been identified on this License.

In late October 2013, we were the high bidder as operator of two deepwater blocks in the pre-salt play offshore Gabon. One of the blocks has since been withdrawn by the government. Award of the other block is subject to government approval and negotiation of an exploration and production sharing contract.

Kenya – We hold a 50 percent non-operated working interest in Block 9, consisting of 3.9 million gross (1.9 million net) acres in northwest Kenya. The first exploratory well on Block 9, the Bahasi-1, completed drilling in the fourth quarter of 2013 and was plugged and abandoned. The Sala-1 exploration well is expected to spud in February 2014 on the eastern side of Block 9, where previous wells drilled in the sub-basin confirmed a working petroleum system. We have the right to assume the role of operator on Block 9 if a commercial discovery is made.

We also hold a 15 percent non-operated working interest in Block 12A, covering 5 million gross (750,000 net) acres, which is also located in northwest Kenya. Seismic acquisition on Block 12A began in 2013 and will be completed in the first quarter of 2014.

Ethiopia – We hold a 20 percent non-operated interest in the onshore South Omo Block in Ethiopia. The concession has an area of approximately 5.4 million gross (1.1 million net) acres. The Sabisa-1 exploration well encountered reservoir quality sands, oil and heavy gas shows and a thick shale section. The presence of oil prone source rocks, reservoir sands and good seals is encouraging for the numerous fault bounded traps identified in the basin. Because of mechanical issues, the well was abandoned before a full evaluation could be completed. The Tultule-1 exploration well was also drilled in 2013, approximately two miles from the Sabisa-1 well in a frontier rift basin and was plugged and abandoned. At least two additional exploration wells are planned for the eastern side of the block in 2014 to test multiple sub-basins. The first of those wells, Shimela-1, is expected to spud in March 2014.

Europe

As discussed above, we commenced efforts in December 2013 to market our assets in the North Sea, including Norway and the U.K.

Norway – Production – At the end of 2013, we operated 9 licenses and held interests in 6 non-operated licenses, which encompass approximately 286,000 net acres offshore on the Norwegian continental shelf. In 2013, net sales from Norway averaged 71 mbbld of liquid hydrocarbons and 51 mmcfd of natural gas.

Our production operations in Norway are centered around the Alvheim complex which consists of an FPSO with subsea infrastructure tied to several producing developments. Produced oil is transported by shuttle tanker and produced natural gas is transported to the SAGE system by pipeline. Production in 2013 continued to benefit from slower than expected decline as a result of infill well success, reservoir management techniques, extended drilling capability and technology application. We safely completed a planned turnaround in nine days in 2013 on time and on budget. Operational availability continued to be a strong factor in 2013 performance with a rate of 96 percent and internal unplanned losses of one percent.

The Alvheim development is comprised of the Kameleon, East Kameleon and Kneler fields (PL 036C, PL 088BS and PL 203), in each of which we have a 65 percent operated working interest, and the Boa field, in which we have a 58 percent operated working interest. At the end of 2013, the Alvheim development included 12 producing, 3 temporarily shut-in and 2 water disposal wells. One infill well is planned for 2014 along with several well workovers.

The Vilje field (PL 036D), in which we own a 47 percent operated working interest, began producing through the Alvheim complex in August 2008. Vilje has two subsea templates and two production wells, and is tied back through a 12-mile pipeline to the Alvheim FPSO. A third production well, Vilje Sor, will be developed as a subsea tieback to the Vilje field. Production start-up is expected in the first half of 2014.

The Volund field (PL 150 and PL 150B), located five miles south of the Alvheim complex consists of four production wells and one water injection well at December 31, 2013. We own a 65 percent operated working interest in Volund.

The Viper oil discovery, in the immediate vicinity of the Volund Field, was announced in November 2009. Along with our partners, we are evaluating a possible tie-back to the Alvheim complex of the Viper discovery as a combined development with the 1997 Kobra discovery. Both discoveries are within PL203 where we hold a 65 percent operated working interest.

Norway – Exploration – The Boyla field (PL 340), formerly the Marihone discovery, is located approximately 17 miles south of the Alvheim complex. In October 2012, the Norwegian Ministry of Petroleum and Energy approved the plan for the development and operation of the Boyla field in which we hold a 65 percent operated working interest. Further development drilling is planned in the Boyla field in 2014, with first production expected in early 2015. Near Boyla, the Caterpillar discovery (PL 340BS) made in 2011 continues to be evaluated as a tie-back to the Alvheim complex through Boyla.

The Darwin (formerly Veslemoy) exploration well was drilled in the first quarter of 2013 on PL 531, in which we hold a 10 percent non-operated fully-carried working interest, and was plugged and abandoned. The 30 percent non-operated Sverdrup exploration well on PL 330 offshore Norway was drilled in the third quarter of 2013 and has been plugged and abandoned.

In January 2013, we were awarded a 20 percent non-operated working interest in PL 694, which consists of three blocks, south of the Sverdrup prospect area. We were also awarded additional acreage in the North Sea, north of the Alvheim area in PL 203B. Our 65 percent working interest and role as operator are the same as PL 203. In addition, in 2013 we withdrew from three licenses (PL505, PL505BS and PL570).

United Kingdom – Net sales from the U.K. averaged 15 mbbld of liquid hydrocarbons and 32 mmcfd of natural gas in 2013. 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 and East Brae fields are natural gas condensate fields which are produced via the Brae Bravo and the East Brae platforms, respectively. The East Brae platform also hosts the nearby Braemar field in which we have a 28 percent working interest. Two development wells are in the West Brae program, with the first to be spud in 2014. Operational availability was 92 percent and internal unplanned losses were eight percent.

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 30 third-party fields are contracted to use the Brae system and 62 mboed are being processed or transported through the Brae infrastructure. In addition to generating processing and pipeline tariff revenue, this third-party business optimizes infrastructure usage.

The working interest owners of the Brae area producing assets collectively own a 50 percent interest in the non-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.

We own working interests in the non-operated Foinaven area complex, consisting of a 28 percent working interest in the main Foinaven field, a 47 percent working interest in East Foinaven and a 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.

Poland – After an extensive evaluation of our exploration activities in Poland and unsuccessful attempts to find commercial levels of hydrocarbons, we have elected to conclude operations in the country. During 2013, we relinquished 7 of our 11 operated concessions to the government and are in the process of relinquishing the remainder.

Other International

Kurdistan Region of Iraq – In aggregate, we have access to approximately 145,000 net acres in the Kurdistan Region of Iraq. We have interests in two non-operated blocks located north-northwest of Erbil: Atrush with 15 percent working interest and Sarsang with 25 percent working interest. We also have a 45 percent operated working interest in the Harir block located northeast of Erbil.

On the non-operated Atrush block, following the successful appraisal program and a declaration of commerciality, a plan for field development was approved by the Kurdistan Ministry of Natural Resources in September 2013. The development project will consist of drilling three production wells and constructing a central processing facility. We expect first production by early 2015 with estimated initial gross production of approximately 30 mbbld of oil. The approval of the field development plan for Phase 1 provides for a 25-year production period. Subject to further drilling and testing results, and partner and government approvals, a potential Phase 2 development could add an additional gross 30 mbbld facility. Within the potential Phase 2 development area, the Atrush-3 appraisal well, located approximately four miles east of existing wells, confirmed the extension of the oil bearing reservoirs and has been suspended as a potential future producer. Testing has commenced on the Atrush-4 development well, spud in October 2013, with anticipated completion in the first quarter of 2014. The Atrush-5 development well is expected to spud in the second quarter of 2014.

On the non-operated Sarsang block, tests have been completed on the Gara well. All zones were water-wet and the well was plugged and abandoned in August 2013. On the Mangesh well, five drill stem tests have been completed and further testing is planned. The East Swara Tika exploration well, which began in July 2013, has been drilled to a depth of 5,300 feet toward a planned total depth of 11,000 feet. This well will test additional resource potential to the northeast of the Swara Tika discovery.

On the operated Harir block, we announced the Mirawa-1 discovery in October 2013. The Mirawa-1 was drilled to a total depth of approximately 14,000 feet and encountered multiple stacked oil and natural gas producing zones with equipment constrained test flow rates of more than 11 mbbld of oil, 72 mmcfd of non-associated natural gas and 1,700 bbld of condensate. We have suspended the well for potential future use as a producing well. The Jisik-1 prospect, located nine miles to the northwest of the Mirawa-1 discovery, will test a similar structure. Drilling on the Jisik-1 prospect commenced in December 2013 and is expected to reach total depth in the second quarter of 2014. The Mirawa-2 appraisal well is expected to spud in the third quarter of 2014, subject to government approval of the Mirawa appraisal plan.

Acquisitions and Dispositions

In June and December 2013, we entered into agreements, valued in total at $2.1 billion before closing adjustments, to sell our non-operated 10 percent working interests in the Production Sharing Contracts and Joint Operating Agreements for Angola Blocks 31 and 32. The sale of our interest in Block 31 closed in February 2014 and the sale of our interest in Block 32 is expected to close in the first quarter of 2014. Our Angola operations are reported as

discontinued operations for all periods presented.
In October of 2013, we transfered our 45 percent working interest and operatorship in the Safen Block in the Kurdistan Region of Iraq at a pretax loss of $17 million.
In January 2013, government approval was received for our acquisition of a 20 percent non-operated interest in the onshore South Omo concession in Ethiopia.
The above discussions include forward-looking statements with respect to anticipated future exploratory and development drilling activity in the Kurdistan Region of Iraq, Ethiopia, Kenya, Norway, the U.K., and E.G., the anticipated start-up date of the

compression project in E.G., the unitization of Block D and the Alba field in E.G., the award of one block in Gabon, plans to exit Poland, the possible sale of our U.K. and Norway assets, the timing of first production from the Boyla field, the timing of first production from the Atrush development, a potential Phase 2 development in the Atrush block, other potential development projects and the sale of our interest in Angola Block 32. Some factors which could possibly affect these forward-looking statements include pricing, supply and demand for liquid hydrocarbons and natural gas, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, the inability to obtain or delay in obtaining necessary government and third-party approvals and permits, 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 award of the block in Gabon is subject to government approval and negotiation of an exploration and production sharing contract. The possible sale of our U.K. and Norway assets is subject to the identification of one or more buyers, successful negotiations, board approval and execution of definitive agreements. The timing of closing the sale of our interest in Block 32 is subject to customary closing conditions. 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 difficult to predict. 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 North America E&P and International E&P segments and discontinued operations combined, the following tables set forth gross and net productive wells and service wells as of December 31, 2013, 2012 and 2011 and drilling wells as of December 31, 2013.

	Productive Wells[a]							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2013								
U.S.	6,632	2,568	2,763	1,482	2,349	744	58	28
E.G.	—	—	16	11	2	1	—	—
Other Africa	1,072	175	7	1	99	16	8	1
Total Africa	1,072	175	23	12	101	17	8	1
Total Europe	77	34	40	16	28	11	—	—
Total Other International	—	—	—	—	—	—	2	1
Worldwide	7,781	2,777	2,826	1,510	2,478	772	68	30
2012								
U.S.	6,191	2,315	3,208	1,906	2,328	736		
E.G.	—	—	14	9	4	3		
Other Africa	1,050	171	6	1	101	16		
Total Africa	1,050	171	20	10	105	19		
Total Europe	77	34	40	16	28	11		
Worldwide	7,318	2,520	3,268	1,932	2,461	766		
2011								
U.S.	5,809	2,058	3,121	1,876	2,313	734		
E.G.	—	—	14	9	4	3		
Other Africa[b]	—	—	—	—	1	—		
Total Africa	—	—	14	9	5	3		
Total Europe	73	31	40	16	28	10		
Worldwide	5,882	2,089	3,175	1,901	2,346	747		

(a) Of the gross productive wells, wells with multiple completions operated by us totaled 204, 188 and 168 as of December 31, 2013, 2012 and 2011. 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.

Drilling Activity

For our North America E&P and International E&P segments and discontinued operations combined, 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	
2013									
U.S.	237	20	—	257	73	13	3	89	346
Total Africa	4	—	—	4	1	—	2	3	7
Total Europe	—	—	—	—	—	—	2	2	2
Total Other International	—	—	—	—	—	—	1	1	1
Worldwide	241	20	—	261	74	13	8	95	356
2012									
U.S.	172	21	2	195	117	13	9	139	334
Total Africa	4	—	—	4	1	—	—	1	5
Total Europe	3	—	—	3	—	—	—	—	3
Worldwide	179	21	2	202	118	13	9	140	342
2011									
U.S.	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	3	70	37	4	2	43	113

[(a)] Activity in Libya through February 2011.

Acreage

We believe we have satisfactory title to our North America E&P and International E&P 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 acreage held in our North America E&P and International E&P segments and discontinued operations combined as of December 31, 2013.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
U.S.	1,720	1,289	695	523	2,415	1,812
Canada	—	—	142	54	142	54
Total North America	1,720	1,289	837	577	2,557	1,866
E.G.	45	29	183	164	228	193
Other Africa	12,921	2,109	18,549	4,463	31,470	6,572
Total Africa	12,966	2,138	18,732	4,627	31,698	6,765
Total Europe	179	88	2,030	748	2,209	836
Other International	—	—	466	145	466	145

Worldwide	14,865	3,515	22,065	6,097	36,930	9,612

In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future. If production is not established or we take no other action to extend the terms of the leases, licenses, or concessions, undeveloped acreage listed in the table below will expire over the next three years. We plan to continue the terms of many of these licenses and concession areas or retain leases through operational or administrative actions. For leases expiring in 2014 that we do not intend to extend or retain, unproved property impairments were recorded in 2013.

	Net Undeveloped Acres Expiring		
(In thousands)	2014	2015	2016
U.S.	145	60	46
E.G. [(a)]	36	—	—
Other Africa	189	2,605	189
Total Africa	225	2,605	189
Total Europe	216	372	1
Other International	—	20	—
Worldwide	586	3,057	236

[(a)] An exploratory well is planned on this acreage in 2014.

Oil Sands Mining Segment

We hold a 20 percent non-operated interest in the AOSP, an oil sands mining and upgrading 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 and vacuum gas oil.

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. The 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 AOSP's Scotford upgrader is at Fort Saskatchewan, northeast of Edmonton, Alberta. 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 oils 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 of December 31, 2013, we own or have rights to participate in developed and undeveloped leases totaling approximately 159,000 gross (32,000 net) acres. The underlying developed leases are held for the duration of the project, with royalties payable to the province of Alberta. Synthetic crude oil sales volumes for 2013 were 48 mbbld and net-of-royalty production was 42 mbbld.

In December 2013, a Jackpine mine expansion project received conditional approval from the Canadian government. The project includes additional mining areas, associated processing facilities and infrastructure. The government conditions relate to wildlife, the environment and aboriginal health issues. We will begin evaluating the potential expansion project and government conditions after current debottlenecking activities are complete and reliability improves.

The governments of Alberta and Canada have agreed to partially fund Quest CCS for 865 million Canadian dollars. In the third quarter of 2012, the Energy and Resources Conservation Board ("ERCB"), Alberta's primary energy regulator at that time, conditionally approved the project and the AOSP partners approved proceeding to construct and operate Quest CCS. Government funding has commenced and will continue to be paid as milestones are achieved during the development, construction and operating phases. Failure of the AOSP to meet certain timing, performance and operating objectives may result in repaying some of the government funding. Construction and commissioning of Quest CCS is expected to be completed by late 2015.

In May 2013, we announced that we terminated our discussions with respect to a potential sale of a portion of our 20 percent outside-operated interest in the AOSP.

The above discussion contains forward-looking statements with regard to the Jackpine mine expansion and Quest CCS. Some factors that could affect the Jackpine mine expansion include the inability to obtain or delay in obtaining third-party approvals and permits. The Quest CCS is subject to the inability to obtain or delay in obtaining government funds, the availability of materials and labor, unforeseen hazards such as weather conditions and other risks customarily associated with these types of projects. 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 difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Reserves

Estimated Reserve Quantities

The following table sets forth estimated quantities of our 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, 2013, 2012 and 2011. Included in our liquid hydrocarbon reserves are NGLs which represent approximately 7 percent, 6 percent and 5 percent of our total proved reserves on an oil equivalent barrel basis as of December 2013, 2012 and 2011. Approximately 72 percent, 63 percent and 40 percent of those NGL reserves are associated with our U.S. unconventional resource plays as of December 31, 2013, 2012 and 2011. Reserves are disclosed by continent and 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. Due to the agreements entered in 2013 to sell our Angola assets, estimated proved reserves for Angola are reported as discontinued operations ("Disc Ops") for all presented periods. Approximately 73 percent of our December 31, 2013 proved reserves are located in OECD countries.

	North America			Africa			Europe		
December 31, 2013	U.S.	Canada	Total	E.G.	Other	Total	Total	Disc Ops	Grand Total
Proved Developed Reserves									
Liquid hydrocarbons (mmbbl)	292	—	292	55	176	231	78	19	620
Natural gas (bcf)	540	—	540	823	95	918	41	—	1,499
Synthetic crude oil (mmbbl)	—	674	674	—	—	—	—	—	674
Total proved developed reserves (mmboe)	382	674	1,056	193	192	385	84	19	1,544
Proved Undeveloped Reserves									
Liquid hydrocarbons (mmbbl)	324	—	324	43	39	82	11	9	426
Natural gas (bcf)	485	—	485	497	110	607	80	—	1,172
Synthetic crude oil (mmbbl)	—	6	6	—	—	—	—	—	6
Total proved undeveloped reserves (mmboe)	405	6	411	125	57	182	25	9	627
Total Proved Reserves									
Liquid hydrocarbons (mmbbl)	616	—	616	98	215	313	89	28	1,046
Natural gas (bcf)	1,025	—	1,025	1,320	205	1,525	121	—	2,671
Synthetic crude oil (mmbbl)	—	680	680	—	—	—	—	—	680
Total proved reserves (mmboe)	787	680	1,467	318	249	567	109	28	2,171

December 31, 2012	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Europe Total	Disc Ops	Grand Total
Proved Developed Reserves									
Liquid hydrocarbons (mmbbl)	198	—	198	68	168	236	84	—	518
Natural gas (bcf)	546	—	546	980	99	1,079	28	—	1,653
Synthetic crude oil (mmbbl)	—	653	653	—	—	—	—	—	653
Total proved developed reserves (mmboe)	289	653	942	231	185	416	88	—	1,446
Proved Undeveloped Reserves									
Liquid hydrocarbons (mmbbl)	277	—	277	42	41	83	5	18	383
Natural gas (bcf)	497	—	497	444	110	554	75	—	1,126
Total proved undeveloped reserves (mmboe)	360	—	360	116	59	175	18	18	571
Total Proved Reserves									
Liquid hydrocarbons (mmbbl)	475	—	475	110	209	319	89	18	901
Natural gas (bcf)	1,043	—	1,043	1,424	209	1,633	103	—	2,779
Synthetic crude oil (mmbbl)	—	653	653	—	—	—	—	—	653
Total proved reserves (mmboe)	649	653	1,302	347	244	591	106	18	2,017

December 31, 2011	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Europe Total	Disc Ops	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	43	82	13	18	251
Natural gas (bcf)	321	—	321	467	—	467	79	—	867
Total proved undeveloped reserves (mmboe)	191	—	191	117	43	160	26	18	395
Total Proved Reserves									
Liquid hydrocarbons (mmbbl)	279	—	279	117	222	339	97	18	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	239	618	117	18	1,800

The increase in proved reserves from 2012 to 2013 was primarily due to drilling programs in our U.S. unconventional shale plays and better than expected performance in Norway. Synthetic crude oil reserves also increased due to approval of an improved recovery project and price and cost changes.

The above estimated quantities of 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 proved 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

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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

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 his staff of Reserve Coordinators. Liquid hydrocarbon and natural gas reserve estimates are developed or reviewed by Qualified Reserves Estimators ("QREs"). QREs are engineers or geoscientists with at least 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 QRE training course. Reserve Coordinators screen all fields with proved reserves of 20 mmboe or greater, every year, to determine if a field review will be performed. Any change to proved reserve estimates in excess of 1 mmboe on a total field basis, within a single month, 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 is a registered Professional Engineer in the State of Texas. In his 26 years with Marathon Oil, he has held numerous engineering and management positions, most recently managing our OSM segment. He is a member of the Society of Petroleum Engineers ("SPE") and a former member of the Petroleum Engineering Advisory Council for the University of Texas at Austin.

Estimates of synthetic crude oil reserves are prepared by GLJ Petroleum Consultants ("GLJ") of Calgary, Canada, third-party consultants. Their reports for all years are filed as exhibits to this Annual Report on Form 10-K. The team lead responsible for the estimates of our synthetic crude oil reserves has over 35 years of experience in petroleum engineering and has conducted surface mineable oil sands evaluations since 1986. He is a member of SPE and served as regional director from 1998 through 2001. The second GLJ team member has 13 years of experience in petroleum engineering and has conducted surface mineable oil sands evaluations since 2009. Both are registered Practicing Professional Engineers 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 and validating our internal reserve estimates. We exceeded this percentage for the four-year period ended December 31, 2013. We have 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 parties 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. In the very limited instances where differences outside the 10 percent tolerance cannot be resolved by year end, a plan to resolve the difference is developed and senior management consent is obtained. The audit process did not result in any significant changes to our reserve estimates for 2013, 2012 or 2011.

During 2013, 2012 and 2011, Netherland, Sewell & Associates, Inc. ("NSAI") prepared a certification of the prior year's reserves for the Alba field in E.G. The NSAI summary reports are filed as an exhibit to this Annual Report on Form 10-K. Members of the NSAI team have many years of industry experience, having worked for large, international oil and gas companies before joining NSAI. The senior technical advisor has over 35 years of practical experience in petroleum geosciences, with over 16 years experience in the estimation and evaluation of reserves. The second team member has over 9 years of practical experience in petroleum engineering, with over 4 years experience in the estimation and evaluation of reserves. Both are registered Professional Engineers in the State of Texas.

Ryder Scott Company ("Ryder Scott") also performed audits of several of our fields in 2013, 2012 and 2011. Their summary reports are filed as exhibits to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 22 years of industry experience, having worked for a major international oil and gas company before joining Ryder Scott. He is a member of SPE, where he served on the Oil and Gas Reserves Committee, and is a registered Professional Engineer in the State of Texas.

Changes in Proved Undeveloped Reserves

As of December 31, 2013, 627 mmboe of proved undeveloped reserves were reported, an increase of 56 mmboe from December 31, 2012. The following table shows changes in total proved undeveloped reserves for 2013:

(mmboe)	
Beginning of year	571
Revisions of previous estimates	4
Improved recovery	7
Purchases of reserves in place	16
Extensions, discoveries, and other additions	142
Dispositions	(4)
Transfer to Proved Developed	(109)
End of year	627

Significant additions to proved undeveloped reserves during 2013 included 72 mmboe in the Eagle Ford and 49 mmboe in the Bakken shale plays due to development drilling. Transfers from proved undeveloped to proved developed reserves included 57 mmboe in the Eagle Ford, 18 mmboe in the Bakken and 7 mmboe in the Oklahoma resource basins due to producing wells. Costs incurred in 2013, 2012 and 2011 relating to the development of proved undeveloped reserves, were $2,536 million, $1,995 million and $1,107 million.

A total of 59 mmboe was booked as a result of reliable technology. Technologies included statistical analysis of production performance, decline curve analysis, rate transient analysis, reservoir simulation and volumetric analysis. The statistical nature of production performance coupled with highly certain reservoir continuity or quality within the reliable technology areas and sufficient proved undeveloped locations establish the reasonable certainty criteria required for booking reserves.

Projects can remain in proved undeveloped reserves for extended periods in certain situations such as large development projects which take more than five years to complete, or the timing of when additional gas compression is needed. Of the 627 mmboe of proved undeveloped reserves at December 31, 2013, 24 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 E.G. that was sanctioned by our Board of Directors in 2004. The timing of the installation of compression is being driven by the reservoir performance with this project intended to maintain maximum production levels. Performance of this field since the Board sanctioned the project has far exceeded expectations. Estimates of initial dry gas in place increased by roughly 10 percent between 2004 and 2010. During 2012, the compression project received the approval of the E.G. government, allowing design and planning work to progress towards implementation, with completion expected by mid-2016. The other component of Alba proved undeveloped reserves is an infill well approved in 2013 and to be drilled late 2014.

Proved undeveloped reserves for the North Gialo development, located in the Libyan Sahara desert, were booked for the first time as proved undeveloped reserves in 2010. This development, 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. Anecdotal evidence from similar development projects in the region led to an expected project execution of more than five years from the time the reserves were initially booked. Interruptions associated with the civil unrest in 2011 and third-party labor strikes in 2013 have extended the project duration. There are no other significant undeveloped reserves expected to be developed more than five years after their original booking.

As of December 31, 2013, future development costs estimated to be required for the development of proved undeveloped liquid hydrocarbon, natural gas and synthetic crude oil reserves related to continuing operations for the years 2014 through 2018 are projected to be $2,894 million, $2,567 million, $2,020 million, $1,452 million and $575 million.

The timing of future projects and estimated future development costs relating to the development of proved undeveloped liquid hydrocarbon, 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		
	U.S.	Canada	Total	E.G.	Other	Total	Total	Disc Ops	Grand Total
2013									
Liquid hydrocarbons (mbbld)[(a)]	149	—	149	34	24	58	86	10	303
Natural gas (mmcfd)[(b)(c)]	312	—	312	442	22	464	76	—	852
Synthetic crude oil (mbbld)[(d)]	—	42	42	—	—	—	—	—	42
Total production sold (mboed)	201	42	243	107	27	134	99	10	486
2012									
Liquid hydrocarbons (mbbld)[(a)]	107	—	107	36	42	78	97	—	282
Natural gas (mmcfd)[(b)(c)]	358	—	358	428	15	443	86	—	887
Synthetic crude oil (mbbld)[(d)]	—	41	41	—	—	—	—	—	41
Total production sold (mboed)	166	41	207	108	44	152	111	—	470
2011									
Liquid hydrocarbons (mbbld)[(a)]	75	—	75	38	5	43	101	—	219
Natural gas (mmcfd)[(b)(c)]	326	—	326	443	—	443	81	—	850
Synthetic crude oil (mbbld)[(d)]	—	38	38	—	—	—	—	—	38
Total production sold (mboed)	129	38	167	112	5	117	115	—	399

(a) The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) U.S. natural gas volumes exclude volumes produced in Alaska prior to our disposal of those assets in 2013 that were stored for later sale in response to seasonal demand, although our reserves had been reduced by those volumes.

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

(d) Upgraded bitumen excluding blendstocks.

Average Sales Price per Unit

	North America			Africa				Europe		
(Dollars per unit)	U.S.	Canada	Total	E.G.		Other	Total	Total	Disc Ops	Grand Total
2013										
Liquid hydrocarbons (bbl)	$85.20	$—	$85.20	$60.34		$122.92	$86.29	$112.60	$104.77	$93.83
Natural gas (mcf)	3.84	—	3.84	0.24	(a)	5.44	0.49	12.13	—	2.75
Synthetic crude oil (bbl)	—	87.51	87.51	—		—	—	—	—	87.51
2012										
Liquid hydrocarbons (bbl)	$85.80	$—	$85.80	$64.33		$127.31	$98.52	$115.16	$—	$99.46
Natural gas (mcf)	3.92	—	3.92	0.24	(a)	5.76	0.43	10.45	—	2.80
Synthetic crude oil (bbl)	—	81.72	81.72	—		—	—	—	—	81.72
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	(a)	0.70	0.24	9.75	—	2.96
Synthetic crude oil (bbl)	—	91.65	91.65	—		—	—	—	—	91.65

(a) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and EGHoldings, which are equity method investees. We include our share of income from each of these equity method investees in our International E&P Segment.

Average Production Cost per Unit[a]

	North America			Africa			Europe		
(Dollars per boe)	U.S.	Canada[b]	Total	E.G.	Other[c]	Total	Total	Disc Ops	Grand Total
2013	$13.60	$55.42	$20.79	$2.88	$7.40	$3.80	$13.68	$11.89	$14.47
2012	13.61	53.61	21.51	3.59	3.57	3.59	9.62	—	12.91
2011	16.51	59.04	25.97	2.92	12.22	3.34	8.85	—	14.42

(a) Production, severance and property taxes are excluded from the production costs used in this calculation. See Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities - Results of Operations for Oil and Gas Production Activities for more information regarding production cost.

(b) Production costs in 2011 include a $64 million water abatement accrual.

(c) Production operations ceased in Libya in February 2011, resuming in 2012, but ceased again in the third quarter of 2013. Fixed costs continue to be incurred in these periods of downtime.

Marketing and Midstream

Our operating segments include activities related to the marketing and transportation of substantially all of our liquid hydrocarbon, synthetic crude oil and natural gas production. These activities include the transportation of production to market centers, the sale of commodities to third parties and the storage of production. We balance our various sales, storage and transportation positions in order to aggregate volumes to satisfy transportation commitments and to achieve flexibility within product types and delivery points. Such activities can include the purchase of commodities from third parties for resale.

As discussed previously, we currently own and operate gathering systems and other midstream assets in some of our production areas. We continue to evaluate midstream infrastructure investments in connection with our development plans.

Delivery Commitments

We have committed to deliver quantities of crude oil and synthetic crude oil to customers under a variety of contracts. As of December 31, 2013, those contracts for fixed and determinable quantities were at variable, market-based pricing and related primarily to Eagle Ford and Bakken liquid hydrocarbon production and OSM synthetic crude oil production. A minimum of 54 mbbld of Eagle Ford liquid hydrocarbon production is to be delivered through mid-2017 under two contracts. Under a 6-year contract ending May 2016, 15 mbbld of Bakken liquid hydrocarbon production is to be delivered. Under a 3-year contract expected to commence mid-2014, 14 mbbld of synthetic crude oil production is to be delivered. Our current production rates and proved reserves are sufficient to meet these commitments. The Eagle Ford and OSM contracts also provide the options of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate. The Bakken contract carries no penalty for shortfalls.

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. Based upon statistics compiled in the "2013 Global Upstream Performance Review" published by IHS Herold Inc., we rank ninth among U.S.-based petroleum companies on the basis of 2012 worldwide liquid hydrocarbon and natural gas production. See Item 1A. Risk Factors for discussion of specific areas in which we compete and related risks.

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 for liquid hydrocarbons, synthetic crude oil and natural gas, as well as changes in competitive conditions in the markets we serve. Generally, results from oil and gas production and OSM 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 the 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 we operate have their own 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 strict 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 2012, the U.S. EPA published final New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP") that amended existing NSPS and NESHAP standards for oil and gas facilities as well as created a new NSPS for oil and gas production, transmission and distribution facilities. These rules, which were updated in August 2013, have been challenged, and negotiations with the U.S. EPA over proposed changes to the rules continue. Compliance with these new rules will result in an increase in the costs of control equipment and labor and require additional notification, monitoring, reporting and recordkeeping for some of our facilities. The U.S. EPA was also notified in December 2012 that seven northeastern states intend to sue the U.S. EPA for failure to include methane standards in these rules. If successfully challenged, the addition of methane standards could further increase our costs to comply with these rules.

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. Rather than issuing pre-construction permits for our facilities on Tribal Lands in North Dakota, in August of 2012, the U.S. EPA finalized an Interim Final Rule under the CAA that requires certain control equipment, recordkeeping, monitoring, and reporting with respect to these facilities. Compliance with this new rule will result in an increase in the costs of control, equipment and labor and will require additional notification, monitoring, reporting and recordkeeping for our facilities on Tribal Lands in North Dakota.

The U.S. EPA is expected to propose the results of its 5-year review of the 2008 ozone National Ambient Air Quality Standards (“NAAQS”) in 2014, which are expected to encompass a proposal for a lower ozone NAAQS. A more stringent ozone NAAQS could result in additional areas being designated as non-attainment, including areas in which we operate, which may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Although there may be an adverse financial impact (including compliance costs, potential permitting delays and increased regulatory requirements) associated with any regulation or other action by the U.S. EPA that lowers the ozone

NAAQS, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding any additional measures and how they will be implemented.

At the end of 2013, the U.S. EPA indicated that, in addition to sources already regulated under the current NSPS subpart OOOO, the U.S. EPA is considering petitions from members of the public to address other sources of emissions from oil and gas operations such as pneumatics, equipment leaks, liquids unloading, and associated gas. At this time, it is uncertain how the U.S. EPA may address these sources (e.g., additional regulations or voluntary programs), what the scope may be, what emission control levels or technology are being considered or the U.S. EPA's timing. Although there may be an adverse financial impact associated with any such 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 present uncertainty regarding any additional measures and how they will be implemented.

Climate Change

In 2010, the U.S. EPA promulgated rules that require 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 cases 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 additional regulation affecting the hydraulic fracturing process, including subjecting the process to regulation under the Safe Drinking Water Act. 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 issued a progress report in late 2012, and expects to issue a draft report for public comment and peer review in 2014, with a final report expected in 2016.

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 open-pit mines, 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 tailings 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 ERCB issued a directive which more clearly defines criteria for managing oil sands tailings. We believe that we are substantially in compliance with the directive at this time. We could incur additional costs if further new regulations are issued or if we fail to comply in a timely manner.

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 2013, sales to British Petroleum and its affiliates accounted for more than 10 percent of our annual revenues. For 2012, sales to Statoil and to Shell Oil and its affiliates each accounted for more than 10 percent of our annual revenues. For 2011, 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.

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 3,359 active, full-time employees as of December 31, 2013. 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, 2014, are as follows:

Lee M. Tillman	52	President and Chief Executive Officer
John R. Sult	54	Executive Vice President and Chief Financial Officer
Sylvia J. Kerrigan	48	Executive Vice President, General Counsel and Secretary
Annell R. Bay	58	Vice President, Global Exploration
T. Mitch Little	50	Vice President, International and Offshore Production Operations
Lance W. Robertson	41	Vice President, North America Production Operations
Howard J. Thill	54	Vice President, Corporate, Government and Investor Relations

With the exception of Mr. Tillman, Mr. Sult and Mr. Robertson, 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. Tillman was appointed president and chief executive officer effective August 2013. Mr. Tillman is also a member of our Board of Directors. Prior to this appointment, Mr. Tillman served as vice president of engineering for ExxonMobil Development Company. Between 2007 and 2010, Mr. Tillman served as North Sea production manager and lead country manager for subsidiaries of ExxonMobil, located in Stavanger, Norway. Mr. Tillman began his career in the oil and gas industry at Exxon Corporation in 1989 as a research engineer and has extensive operations management and leadership experience.
- Mr. Sult was appointed executive vice president and chief financial officer effective September 2013. Prior to this appointment, Mr. Sult served as executive vice president and chief financial officer of El Paso Corporation from 2010 to 2012, senior vice president and chief financial officer from 2009 until 2010, and senior vice president, chief accounting officer and controller from 2005 until 2009.
- Ms. Kerrigan was appointed executive vice president, general counsel and secretary effective October 2012, and was appointed general counsel and secretary effective November 2009. Prior to these appointments, Ms. Kerrigan was assistant general counsel since January 2003.
- Ms. Bay was appointed vice president, global exploration effective July 2011. Ms. Bay joined Marathon Oil in June 2008 as senior vice president, exploration.
- Mr. Little was appointed vice president, international and offshore production operations in September 2013 and served as vice president, international production operations effective September 2012. Prior to this appointment, Mr. Little was resident manager for our Norway operations and served as general manager, worldwide drilling and completions. Mr. Little joined Marathon Oil in 1986 and has held a number of engineering and management positions of increasing responsibility.
- Mr. Robertson was appointed vice president, North America production operations in September 2013 and served as vice president, Eagle Ford production operations since October 2012. Mr. Robertson joined Marathon Oil in October 2011 as regional vice president, South Texas/Eagle Ford. Between 2004 and 2011, Mr. Robertson held a number of senior engineering and operations management roles of increasing responsibility with Pioneer Natural Resources in the U.S. and Canada.
- Mr. Thill was appointed vice president, corporate, government and investor relations effective January 2014, and 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://marathonoil.com/Investor_Center/Corporate_Governance/.

Our Annual Reports 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. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K.

A substantial, 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 tornadoes;
- the price and availability of alternative and competing forms of energy;
- the effect of conservation efforts;
- 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 Annual Report on Form 10-K 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 and approved 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 periods ended December 31, 2013, 2012 and 2011, as well as other conditions in existence at those dates. 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.

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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 cash flows from our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves reflected in this Annual Report on Form 10-K 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 cash flows 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 periods ended December 31, 2013, 2012 and 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 cash flows 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 or 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 or 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;
- increased costs or operational delays resulting from shortages of water;
- 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 capital projects.

We may incur substantial capital expenditures and operating costs as a result of compliance with, and/or changes in environmental, health, safety and security laws and regulations, and, as a result, our business, financial condition, results of operations 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 and the protection of endangered species as well as laws, regulations, and other requirements 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, regulations, and other requirements. 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, regulations, and other requirements 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 clean-ups or curtail operations that could materially and adversely affect our business, financial condition, results of operations 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, regulations, and other requirements 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 2013, 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 2012 at the Doha Climate Change Conference, countries agreed to extend the Kyoto Protocol to 2020. However, the U.S. Senate has not ratified the Kyoto Protocol, nor is it clear whether the U.S. Senate plans to ratify this agreement in the future. If the U.S. does ratify the Kyoto Protocol in the future or signs a new international agreement, such actions could result in increased costs to operate and maintain our facilities, capital expenditures to install new emission controls at our facilities, and 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 is conducting a comprehensive research study on the potential effects that hydraulic fracturing may have on water quality and public health, issued a progress report in late 2012, and expects to issue a draft report for public comment and peer review in 2014, with a final report expected in 2016. 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 liquid hydrocarbons and natural gas, including from the 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.

Worldwide political and economic developments and changes in law could adversely affect 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 55 percent of our liquid hydrocarbon and natural gas sales volumes in 2013 was derived from production outside the U.S. and 47 percent of our proved liquid hydrocarbon and natural gas reserves as of December 31, 2013 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 within or outside of the U.S. There are many risks associated with operations in countries such as E.G., Angola, Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq and Libya, and in global markets including:

- changes in governmental policies relating to liquid hydrocarbon or natural gas 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, Iraq, 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 legislation and other changes in law, 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. Changes in law could also adversely affect our results, including new regulations resulting in higher costs to transport our production by pipeline, rail car, truck or vessel or the adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information or that could cause us to violate the non-disclosure laws of other countries.

Our commodity price risk management and trading activities may prevent us from fully benefiting from commodity price increases and may expose us to other risks, including counterparty risk.

To the extent that we engage in price risk management activities to protect ourselves against commodity price declines, we may be prevented from fully realizing the benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Our business could be negatively impacted by cyber-attacks targeting our computer and telecommunications systems and infrastructure.

Our business, like other companies in the oil and gas industry, has become increasingly dependent on digital technologies. Such technologies are integrated into our business operations and used as a part of our liquid hydrocarbon and natural gas production and distribution systems in the U.S. and abroad, including those systems used to transport production to market. Use of the internet and other public networks for communications, services, and storage, including "cloud" computing, exposes users (including our business) to cybersecurity risks. While our information systems and related infrastructure experienced attempted and actual minor breaches of our cybersecurity in the past, we have not suffered any losses or breaches which had a material effect on our business, operations or reputation relating to such attacks; however, there is no assurance that we will not suffer such losses or breaches in the future. As cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information systems and related infrastructure security vulnerabilities.

Our operations may be adversely affected by pipeline, rail and other transportation capacity constraints.

The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities, rail cars, trucks and vessels. If any pipelines, rail cars, trucks or vessels become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport our liquid hydrocarbons and natural gas, which could increase the costs and/or reduce the revenues we might obtain from the sale of our production.

If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

We typically seek the acquisition of crude oil and natural gas properties. Although we perform reviews of properties to be acquired in a manner that we believe is diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may they permit us to become sufficiently familiar with the properties in order to fully assess possible deficiencies and potential problems. Even when problems with a property are identified, we often assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. Moreover, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves (as previously discussed), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

We operate in a highly competitive industry, and many of our competitors are larger and have available resources in excess of our own.

The oil and gas industry is highly competitive, and many competitors, including major integrated and independent oil and gas companies, as well as national oil companies, are larger and have substantially greater resources at their disposal than we do. We compete with these companies for the acquisition of oil and natural gas leases and other properties. We also compete with these companies for equipment and personnel, including petroleum engineers, geologists, geophysicists and other specialists, required to develop and operate those properties and in the marketing of crude oil and natural gas to end-users. Such competition can significantly increase costs and affect the availability of resources, which could provide our larger competitors a competitive advantage when acquiring equipment, leases and other properties. They may also be able to use their greater resources to attract and retain experienced personnel.

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 as 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 North America E&P and International E&P 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 OSM 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 our products from our facilities. A prolonged disruption in the ability of any pipelines, rail cars, trucks, or vessels to transport our production 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.

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. In April 2013, we filed a counterclaim against Noble alleging, among other things, breach of contract and breach of the duty of good faith relating to the multi-year drilling contract. The counterclaim also included a breach of contract claim for reimbursement for the value of fuel used by Noble under an offshore daywork drilling contract. The parties settled this litigation in the fourth quarter of 2013, and the settlement did not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Environmental Proceedings

The following is a summary of proceedings involving us that were pending or contemplated as of December 31, 2013 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.

As of December 31, 2013, we have sites across the country where remediation is being sought under 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 total clean-up and remediation costs connected with these sites will be less than $24 million, the majority of which have already been incurred.

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.

Item 4. Mine Safety Disclosures

Not applicable.

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, 2014, there were 41,356 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:

	2013			2012		
(Dollars per share)	High Price	Low Price	Dividends	High Price	Low Price	Dividends
Quarter 1	$35.71	$31.59	$0.17	$35.06	$30.47	$0.17
Quarter 2	$36.38	$29.85	$0.17	$32.23	$23.32	$0.17
Quarter 3	$37.83	$32.61	$0.19	$31.09	$24.09	$0.17
Quarter 4	$37.93	$34.06	$0.19	$31.93	$29.30	$0.17
Full Year	$37.93	$29.85	$0.72	$35.06	$23.32	$0.68

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, 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.

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, 2013, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934:

Period	Column (a) Total Number of Shares Purchased[(a)]		Column (b) Average Price Paid per Share	Column (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(c)]	Column (d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(c)]
10/01/13 – 10/31/13	9,404		$35.07	—	$1,280,820,541
11/01/13 – 11/30/13	5,381		$35.18	—	$1,280,820,541
12/01/13 – 12/31/13	33,682	(b)	$35.84	—	$2,500,000,000
Total	48,467		$35.62	—	

(a) 21,898 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) In December 2013, 26,569 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) In December 2013, our Board of Directors increased the authorization for repurchases of our common stock by $1.2 billion, bringing the remaining share repurchase authorization to $2.5 billion. As of December 31, 2013, we had repurchased 92 million common shares at a cost of $3,722 million, which includes transaction fees and commissions that are not reported in the table above. Of this total, 14 million shares were acquired at a cost of $500 million during the third quarter of 2013, 12 million shares at a cost of $300 million in the third quarter of 2011 and 66 million shares for $2,922 million prior to the spin-off of our downstream business.

Item 6. Selected Financial Data

(In millions, except per share data)	2013[(a)(b)]	2012[(a)(b)]	2011[(a)(b)]	2010[(a)(b)]	2009[(b)]
Statement of Income Data					
Revenues	$ 14,501	$ 15,692	$ 14,669	$ 11,690	$ 8,524
Income from continuing operations	1,593	1,613	1,718	1,448	756
Net income	1,753	1,582	2,946	2,568	1,463
Per Share Data					
Basic:					
Income from continuing operations	$2.26	$2.28	$2.42	$2.04	$1.06
Net income	$2.49	$2.24	$4.15	$3.62	$2.06
Diluted:					
Income from continuing operations	$2.24	$2.27	$2.41	$2.03	$1.06
Net income	$2.47	$2.23	$4.13	$3.61	$2.06
Statement of Cash Flows Data[(b)]					
Additions to property, plant and equipment related to continuing operations	$ 4,766	$ 4,593	$ 2,986	$ 3,269	$ 3,056
Dividends paid	508	480	567	704	679
Dividends per share	$0.72	$0.68	$0.80	$0.99	$0.96
Balance Sheet Data as of December 31:					
Total assets	$ 35,620	$ 35,306	$ 31,371	$ 50,014	$ 47,052
Total long-term debt, including capitalized leases	6,394	6,512	4,674	7,601	8,436

(a) Includes impairments of $96 million, $371 million, $310 million and $447 million in 2013, 2012, 2011 and 2010 (see Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements).

(b) We entered into agreements to sell our Angola assets in 2013 (see Item 8. Financial Statements and Supplementary Data – Note 6 to the consolidated financial statements); our downstream business was spun-off on June 30, 2011 (see Item 8. Financial Statements and Supplementary Data – Note 3 to the consolidated financial statements); and our Ireland and previous Gabon businesses were sold in 2009. The applicable periods have been recast to reflect these businesses in discontinued operations.

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

Each of our segments is organized and managed based upon both geographic location and the nature of the products and services it offers:

- North America E&P – explores for, produces and markets liquid hydrocarbons and natural gas in North America;
- International E&P – explores for, produces and markets liquid hydrocarbons and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.; and
- Oil Sands Mining – 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.

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 the 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 stockholders 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. 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 for all periods prior to the spin-off (see Item 8. Financial Statements and Supplementary Data – Note 3 to the consolidated financial statements for additional information).

Overview – Market Conditions

Prevailing prices for the various qualities of crude oil and natural gas that we produce significantly impact our revenues and cash flows. The following table lists benchmark crude oil and natural gas price averages relative to our North America E&P and International E&P segments for the past three years.

Benchmark	2013	2012	2011
WTI crude oil (Dollars per bbl)	$98.05	$94.15	$95.11
Brent (Europe) crude oil (Dollars per bbl)	$108.64	$111.65	$111.26
Henry Hub natural gas (Dollars per mmbtu)[(a)]	$3.65	$2.79	$4.04

[(a)] Settlement date average.

North America E&P

Liquid hydrocarbons – The quality, location and composition of our liquid hydrocarbon production mix can cause our North America E&P price realizations to differ from the WTI benchmark.

Quality – Light sweet crude contains less sulfur and tends to be lighter than sour crude oil so that refining it is less costly and has historically produced higher value products; therefore, light sweet crude is considered of higher quality and has historically sold at a price that approximates WTI or at a premium to WTI. The percentage of our North America E&P crude oil and condensate production that is light sweet crude has been increasing as onshore production from the Eagle Ford and Bakken increases and production from the Gulf of Mexico declines. In 2013, the percentage of our U.S. crude oil and condensate production that was sweet averaged 76 percent compared to 63 percent and 42 percent in 2012 and 2011.

Location – In recent years, crude oil sold along the U.S. Gulf Coast, such as that from the Eagle Ford, has been priced based on the Louisiana Light Sweet ("LLS") benchmark which has historically priced at a premium to WTI and has historically tracked closely to Brent, while production from inland areas farther from large refineries has been priced lower. The average annual WTI

discount to Brent was narrower in 2013 than in 2012 and 2011. As a result of the significant increase in U.S. production of light sweet crude oil, the historical relationship between WTI, Brent and LLS pricing may not be indicative of future periods.

Composition – The proportion of our liquid hydrocarbon sales volumes that are NGLs continues to increase due to our development of United States unconventional liquids-rich plays. NGLs were 15 percent of our North America E&P liquid hydrocarbon sales volumes in 2013 compared to 10 percent in 2012 and 7 percent in 2011.

Natural gas – A significant portion of our natural gas production in the U.S. is sold at bid-week prices, or first-of-month indices relative to our specific producing areas. Average Henry Hub settlement prices for natural gas were 31 percent higher for 2013 than for 2012.

International E&P

Liquid hydrocarbons – Our International E&P crude oil production is relatively sweet and has historically sold in relation to the Brent crude benchmark, which on average was 3 percent lower for 2013 than 2012.

Natural gas – Our major International E&P natural gas-producing regions are Europe and E.G. Natural gas prices in Europe have been considerably higher than the U.S. in recent years. In the case of E.G., our natural gas sales are subject to term contracts, making realized prices in these areas less volatile. The natural gas sales from E.G. are at fixed prices; therefore, our reported average International E&P natural gas realized prices may not fully track market price movements.

Oil Sands Mining

The Oil Sands Mining segment produces and sells various qualities of synthetic crude oil. Output mix can be impacted by operational problems or planned unit outages at the mines or upgrader. Sales prices for roughly two-thirds of the normal output mix has historically tracked movements in WTI and one-third has historically tracked movements in the Canadian heavy crude oil marker, primarily WCS. The WCS discount to WTI has been increasing on average in each year presented below. Despite a wider WCS discount in 2013, our average Oil Sands Mining price realizations increased due to a greater proportion of higher value synthetic crude oil sales volumes compared to 2012.

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 AECO natural gas sales index and crude oil prices, respectively.

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

Benchmark	2013	2012	2011
WTI crude oil (Dollars per bbl)	$98.05	$94.15	$95.11
WCS (Dollars per bbl)[(a)]	$72.77	$73.18	$77.97
AECO natural gas sales index (Dollars per mmbtu)[(b)]	$3.08	$2.39	$3.68

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

(b) Monthly average day ahead index.

Key Operating and Financial Activities

Significant 2013 activities related to our strategic imperatives:

- Production growth
- Total company net sales volume growth of 11 percent (excluding Alaska and Libya)
- North America E&P net sales volumes averaged 201 mboed, a 21 percent increase over last year
- Eagle Ford averaged net sales volumes of 81 mboed, a 136 percent increase
- Bakken averaged net sales volumes of 39 mboed, a 34 percent increase
- Oklahoma resource basins averaged net sales volumes of 14 mboed, a 68 percent increase
- Proved reserve replacement of 194 percent, excluding dispositions
- Total net proved reserves increased 8 percent to approximately 2.2 billion boe
- Quality resource capture through focused exploration
- Mirawa-1 discovery on operated Harir block in the Kurdistan Region of Iraq
- Diaman-1B discovery on non-operated Diaba License in Gabon
- Atrush block received approval from the KRG for the first phase of oil development in the Kurdistan Region of Iraq
- Shenandoah and Gunflint (both non-operated) prospects had successful appraisal wells in the Gulf of Mexico
- Rigorous portfolio management
- Exceeded three-year $1.5 billion to $3 billion divestiture target
- Agreements to sell working interests in Angola Blocks 31 and 32 with an aggregate transaction value of $2.1 billion, before closing adjustments
- Sold our interests in Alaska, the DJ Basin and the Neptune gas plant
- Acquired 4,800 additional net acres in the core of the Eagle Ford shale
- Grew SCOOP acreage position over 20 percent
- Commenced efforts to market our U.K. and Norway assets
- Competitive shareholder value
- Increased dividend by 12 percent to 19 cents per share
- Repurchased 14 million common shares for $500 million
- Announced $500 million share repurchase to begin upon closing of Angola Block 31 sale
- Authorized $1.2 billion increase in share repurchase program to $2.5 billion remaining

Significant 2014 activity through February 28, 2014 includes:

- Closed sale of our interest in Angola Block 31

Consolidated Results of Operations: 2013 compared to 2012

Consolidated income from continuing operations before income taxes in 2013 was 20 percent lower than 2012 primarily due to lower liquid hydrocarbon net sales volumes in the International E&P segment and higher DD&A and exploration expenses, partially offset by higher liquid hydrocarbon net sales volumes in the North America E&P segment. The effective tax rate for continuing operations was 68 percent in 2013 compared to 74 percent in 2012, with the decrease primarily related to lower income from continuing operations in Libya and Norway, which are higher tax jurisdictions.

Sales and other operating revenues, including related party are summarized by segment in the following table:

(In millions)	2013	2012
Sales and other operating revenues, including related party		
North America E&P	$5,068	$3,944
International E&P	5,827	7,445
Oil Sands Mining	1,576	1,521
Segment sales and other operating revenues, including related party	12,471	12,910
Unrealized gain (loss) on crude oil derivative instruments	(52)	53
Sales and other operating revenues, including related party	$12,419	$12,963

North America E&P sales and other operating revenues increased $1,124 million from 2012 to 2013 primarily due to higher liquid hydrocarbon net sales volumes resulting from ongoing development programs in the Eagle Ford, Bakken and Oklahoma resource basins, partially offset by lower natural gas net sales volumes, primarily the result of the sale of our Alaska assets in early 2013.

The following table gives details of net sales volumes and average price realizations of our North America E&P segment:

	2013	2012
North America E&P Operating Statistics		
Net liquid hydrocarbon sales volumes (mbbld)	149	107
Liquid hydrocarbon average price realizations (per bbl) [(a)] [(b)]	$85.20	$85.80
Net crude oil and condensate sales volumes (mbbld)	126	96
Crude oil and condensate average price realizations (per bbl) [(a)]	$94.19	$91.30
Net natural gas liquids sales volumes (mbbld)	23	11
Natural gas liquids average price realizations (per bbl) [(a)]	$35.12	$39.57
Net natural gas sales volumes (mmcfd)	312	358
Natural gas average price realizations (per mcf) [(a)]	$3.84	$3.92

(a) Excludes gains and losses on derivative instruments.

(b) Inclusion of realized gains (losses) on crude oil derivative instruments would have increased (decreased) average liquid hydrocarbon price realizations per bbl by $(0.27) for 2013 and $0.40 for 2012.

International E&P sales and other operating revenues decreased $1,618 million in 2013 from the prior year. This decrease was primarily due to lower liquid hydrocarbon net sales volumes in Libya and Norway and lower liquid hydrocarbon average price realizations.

The following table gives details of net sales volumes and average price realizations of our International E&P segment:

	2013	2012
International E&P Operating Statistics		
Net liquid hydrocarbon sales volumes (mbbld)[(a)]		
Europe	86	97
Africa	58	78
Total International E&P	144	175
Liquid hydrocarbon average price realizations (per bbl)		
Europe	$112.60	$115.16
Africa	$86.29	$98.52
Total International E&P	$102.10	$107.78
Net natural gas sales volumes (mmcfd)		
Europe[(b)]	83	101
Africa	464	443
Total International E&P	547	544
Natural gas average price realizations (per mcf)		
Europe	$12.08	$10.47
Africa[(c)]	$0.49	$0.43
Total International E&P	$2.25	$2.29

(a) Corresponds with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Includes natural gas acquired for injection and subsequent resale of 7 mmcfd and 15 mmcfd for 2013 and 2012.

(c) 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, AMPCO's and EGHoldings' income in our International E&P segment.

Oil Sands Mining sales and other operating revenues increased $55 million in 2013 from 2012. This increase was primarily due to a higher proportion of net sales volumes related to a premium grade synthetic crude oil and the associated average price realizations when compared to 2012. The increase was partially offset by lower feedstock sales in 2013.

The following table gives details of net sales volumes and average price realizations of our Oil Sands Mining segment:

	2013	2012
Oil Sands Mining Operating Statistics		
Net synthetic crude oil sales volumes (mbbld) [(a)]	48	47
Synthetic crude oil average price realizations (per bbl)	$87.51	$81.72

(a) Includes blendstocks.

Unrealized gains and losses on crude oil derivative instruments are included in total sales and other operating revenues but are not allocated to the segments. These crude oil derivative instruments, all of which had terms that ended in December 2013, resulted in a $52 million net unrealized loss in 2013 compared to a net unrealized gain of $53 million in 2012. See Item 8. Financial Statements and Supplementary Data - Note 16 to the consolidated financial statements for information about our derivative positions.

Marketing revenues decreased $647 million in 2013 from 2012. North America E&P segment marketing activities, which serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points, decreased in 2013 as a result of market dynamics.

Income from equity method investments increased $53 million in 2013 from the prior year primarily due to higher LNG average price realizations.

Net gain (loss) on disposal of assets in 2013 primarily included a $114 million pretax loss on the sale of our interests in the DJ Basin, a $43 million pretax loss on the conveyance of our interests in the Marcellus natural gas shale play to the operator, a $98 million pretax gain on the sale of our interest in the Neptune gas plant, and a $55 million pretax gain on the sale of our remaining assets in Alaska. The net gain on disposal of assets in 2012 consisted primarily of a $166 million pretax gain on the sale of our interests in several Gulf of Mexico crude oil pipeline systems and a $36 million pretax loss related to our exit from Indonesia. See Item 8. Financial Statements and Supplementary Data - Note 6 to the consolidated financial statements for information about these dispositions.

Production expenses increased $129 million in 2013 from 2012 primarily related to increased North America E&P net sales volumes in the Eagle Ford and Bakken and International E&P well workovers in Norway. The production expense rate (expense per boe) decreased in North America E&P in 2013 compared to 2012 primarily due to improved operating efficiencies in the Eagle Ford. The International E&P production expense rate increased in 2013 compared to 2012 primarily due to the well workovers in Norway.

The following table provides production expense rates for each segment:

($ per boe)	2013	2012
North America E&P	$10.86	$11.59
International E&P	$6.24	$5.13
Oil Sands Mining [(a)]	$46.30	$45.95

(a) Production expense per synthetic crude oil barrel (before royalties) includes production costs, shipping and handling, taxes other than income and insurance costs and excludes pre-development costs.

Marketing expenses decreased $672 million in 2013 from the prior year, consistent with the decrease in marketing revenues discussed above.

Exploration expenses were $282 million higher in 2013 than in 2012, primarily due to larger non-cash unproved property impairments in our North America E&P segment related to Eagle Ford leases that either expired or that we did not expect to drill, partially offset by reduced geological and geophysical costs.

The following table summarizes the components of exploration expenses:

(In millions)	2013	2012
Unproved property impairments	$580	$227
Dry well costs	218	230
Geological and geophysical	84	135
Other	106	114
Total exploration expenses	$988	$706

Depreciation, depletion and amortization increased $313 million in 2013 from the prior year. Our segments apply the units-of-production method to the majority of their assets, including capitalized asset retirement costs. Increased DD&A in 2013 primarily reflects the impact of higher North America E&P sales volumes as well as increased amortization of capitalized asset retirement costs due to revisions of estimates for abandonment obligations in the Gulf of Mexico and the U.K. However, the disposition of our Alaska assets in January 2013 and lower International E&P DD&A primarily due to 2013 reserve additions in Norway partially offset the increase. See Item 8. Financial Statements and Supplementary Data - Note 6 to the consolidated financial statements for information about the Alaska disposition.

The DD&A rate (expense per boe), which is impacted by changes in reserves and capitalized costs, can also cause changes to our DD&A. A higher 2013 DD&A rate in North America E&P versus 2012 is due to the ongoing development programs in the U.S. resource plays. A lower International E&P DD&A rate in 2013 compared to 2012 was primarily due to reserve increases for Norway.

The following table provides DD&A rates for each segment:

($ per boe)	2013	2012
North America E&P	$26.23	$23.45
International E&P	$7.26	$8.08
Oil Sands Mining	$12.39	$12.57

Impairments in 2013 primarily related to capitalized costs associated with engineering and feasibility studies for a second LNG production train in E.G., the Ozona development in the Gulf of Mexico, and our Powder River Basin asset in Wyoming. Impairments in 2012 were also related to the Ozona development and Powder River Basin. See Item 8. Financial Statements and Supplementary Data - Note 15 to the consolidated financial statements for information about these impairments.

Taxes other than income include production, severance and ad valorem taxes in the United States, which tend to increase or decrease in relation to net sales volumes and revenues, and increased $104 million in 2013 from 2012. With the increase in North America E&P revenues and net sales volumes, production and severance taxes increased. In addition, ad valorem taxes were higher because the value of our North America E&P assets has increased with continued acquisitions in the Eagle Ford.

Net interest and other increased $55 million in 2013 from 2012 primarily due to higher interest expense related to our $2 billion issuance of senior notes in late 2012. See Item 8. Financial Statements and Supplementary Data - Note 9 to the consolidated financial statements for more detailed information.

Provision for income taxes decreased $1,180 million in 2013 from 2012 primarily due to the decrease in pretax income from continuing operations, primarily in Libya and Norway, which are higher tax jurisdictions. The following is an analysis of the effective tax rates for 2013 and 2012.

	2013		2012	
Statutory rate applied to income from continuing operations before income taxes	35	%	35	%
Effects of foreign operations, including foreign tax credits	14		18	
Adjustments to valuation allowances	18		21	
Other	1		—	
Effective income tax rate on continuing operations	68	%	74	%

The effective income tax rate is influenced by a variety of factors including the geographic sources of income and the relative magnitude of these sources of income. 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 appears in the "Corporate and other unallocated items" shown in the reconciliation of segment income to net income below.

Effects of foreign operations – The effects of foreign operations on our effective tax rate decreased in 2013 as compared to 2012, primarily due to decreased sales in Libya during 2013 as a result of third-party labor strikes at the Es Sider oil terminal.

Adjustments to valuation allowances – In 2013 and 2012, 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 those years.

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

Discontinued operations is presented net of tax. In 2013, we entered into agreements to sell our Angola assets; therefore, the Angola operations are reflected as discontinued operations in all periods presented. See Item 8. Financial Statements and Supplementary Data – Note 6 to the consolidated financial statements.

Segment Results: 2013 compared to 2012

Segment income for 2013 and 2012 is summarized and reconciled to net income in the following table.

(In millions)	2013		2012	
North America E&P	$ 529		$ 382	
International E&P	1,423		1,660	
Oil Sands Mining	206		171	
Segment income	2,158		2,213	
Items not allocated to segments, net of income taxes:				
Corporate and other unallocated items	(473	)	(475	)
Unrealized gain (loss) on crude oil derivative instruments	(33	)	34	
Net gain (loss) on dispositions	(20	)	72	
Impairments	(39	)	(231	)
Income from continuing operations	1,593		1,613	
Discontinued operations	160		(31	)
Net income	$ 1,753		$ 1,582	

North America E&P segment income increased $147 million in 2013 compared to 2012. The increase was largely due to increased liquid hydrocarbon net sales volumes primarily in the Eagle Ford, Bakken and Oklahoma resource basins, partially offset by higher DD&A associated with the higher sales volumes. Segment income was also negatively impacted by higher exploration expenses related to non-cash unproved property impairments and the sale of our Alaska assets.

International E&P segment income decreased $237 million in 2013 compared to 2012. The decrease was primarily related to the lower liquid hydrocarbon net sales volumes in Libya and Norway and lower average liquid hydrocarbon price realizations, as well as higher exploration expenses, partially offset by lower DD&A associated with the lower sales volumes.

Oil Sands Mining segment income increased $35 million in 2013 compared to 2012. This increase was primarily due to a higher proportion of net sale volumes in 2013 related to a premium grade of synthetic crude oil with a higher corresponding price realization.

Consolidated Results of Operations: 2012 compared to 2011

Consolidated income from continuing operations before income taxes in 2012 was 38 percent higher than in 2011 primarily related to increases in North America E&P and International E&P liquid hydrocarbon net sales volumes and higher average price realizations in International E&P. The effective tax rate for continuing operations was 74 percent in 2012 compared to 61 percent in 2011, with the increase primarily related to resumption in 2012 of sales in Libya, which is a higher tax jurisdiction. Also, in 2011 we were not in an excess foreign tax credit position for the entire year as we were in 2012.

Sales and other operating revenues, including related party are summarized by segment in the following table:

(In millions)	2012	2011
Sales and other operating revenues, including related party		
North America E&P	$3,944	$3,364
International E&P	7,445	5,851
Oil Sands Mining	1,521	1,535
Segment sales and other operating revenues, including related party	12,910	10,750
Unrealized gain (loss) on crude oil derivative instruments	53	—
Sales and other operating revenues, including related party	$12,963	$10,750

North America E&P sales and other operating revenues increased $580 million in 2012 from 2011 primarily due to higher liquid hydrocarbon net sales volumes resulting from ongoing development programs in the Eagle Ford and Bakken, partially offset by lower average liquid hydrocarbon and natural gas price realizations, when compared to 2011. Realized gains on our North America E&P crude oil derivative instruments were $15 million in 2012, while there were no open crude oil derivative instruments in 2011.

The following table gives details of net sales volumes and average price realizations of our North America E&P segment:

	2012	2011
North America E&P Operating Statistics		
Net liquid hydrocarbon sales volumes (mbbld)	107	75
Liquid hydrocarbon average price realizations (per bbl) [a][b]	$85.80	$92.55
Net crude oil and condensate sales volumes (mbbld)	96	70
Crude oil and condensate average price realizations (per bbl) [a]	$91.30	$94.80
Net natural gas liquids sales volumes (mbbld)	11	5
Natural gas liquids average price realizations (per bbl) [a]	$39.57	$58.53
Net natural gas sales volumes (mmcfd)	358	326
Natural gas average price realizations (per mcf) [a]	$3.92	$4.95

(a) Excludes gains and losses on derivative instruments.

(b) Inclusion of realized gains on crude oil derivative instruments would have increased average liquid hydrocarbon price realizations by $0.40 per bbl for 2012. There were no crude oil derivative instruments in 2011.

International E&P sales and other operating revenues increased $1,594 million in 2012 from 2011 primarily as a result of the previously discussed resumption of liquid hydrocarbon sales in Libya. Higher average liquid hydrocarbon price realizations during 2012, again primarily related to Libyan crude oil, also contributed to the revenue increase.

The following table gives details of net sales volumes and average price realizations of our International E&P segment:

	2012	2011
International E&P Operating Statistics		
Net liquid hydrocarbon sales volumes (mbbld)[a]		
Europe	97	101
Africa	78	43

Total International E&P	175	144
Liquid hydrocarbon average price realizations (per bbl)		
Europe	$115.16	$115.55
Africa	$98.52	$73.21
Total International E&P	$107.78	$102.96
Net natural gas sales volumes (mmcfd)		
Europe[(b)]	101	97
Africa	443	443
Total International E&P	544	540
Natural gas average price realizations (per mcf)		
Europe	$10.47	$9.84
Africa[(c)]	$0.43	$0.24
Total International E&P	$2.29	$1.97

(a) Corresponds with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Includes natural gas acquired for injection and subsequent resale of 15 mmcfd and 16 mmcfd for 2012 and 2011.

(c) 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, AMPCO's and EGHoldings' income in our International E&P segment.

Oil Sands Mining sales and other operating revenues decreased $14 million in 2012 from 2011. This decrease was primarily the result of lower average price realizations which were partially offset by higher net sales volumes.
The following table gives details of net sales volumes and average price realizations of our Oil Sands Mining segment:

	2012	2011
Oil Sands Mining Operating Statistics		
Net synthetic crude oil sales volumes (mbbld) [(a)]	47	43
Synthetic crude oil average price realizations (per bbl)	$81.72	$91.65

(a) Includes blendstocks.

Unrealized gains and losses on crude oil derivative instruments are included in total sales and other operating revenues but are not allocated to the segments. These crude oil derivative instruments resulted in a net unrealized gain of $53 million in 2012, however, there were no open crude oil derivative instruments in 2011. See Item 8. Financial Statements and Supplementary Data - Note 16 to the consolidated financial statements for additional information about our derivative positions.

Marketing revenues decreased $1,190 million in 2012 from 2011. North America E&P segment marketing activities, which serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points, decreased in 2012 as a result of market dynamics and slightly lower commodity prices.

Income from equity method investments decreased $92 million in 2012 from the prior year primarily due to lower natural gas prices and turnarounds early in 2012 at our facilities in E.G. Also, in January 2012, we sold our equity investments in several Gulf of Mexico crude oil pipelines.

Net gain (loss) on disposal of assets in 2012 consisted primarily of the $166 million pretax gain on the sale of our interests in several Gulf of Mexico crude oil pipeline systems and a $36 million pretax loss related to our exit from Indonesia. In 2011, the net gain on disposal of assets was primarily related to the $37 million pretax gain related to the assignment of interests in our DJ Basin acreage position, the $34 million pretax gain on the sale of our interest in the Burns Point gas plant and the $8 million pretax gain on the sale of our interest in the Alaska LNG facility. See Item 8. Financial Statements and Supplementary Data - Note 6 to the consolidated financial statements for information about these dispositions.

Production expenses increased $251 million in 2012 from 2011. The increase is primarily related to increased liquid hydrocarbon net sales volumes in the Eagle Ford, Bakken and Libya as well as the 2012 planned turnaround in the U.K.

The following table provides production expense rates (expense per boe) for each segment:

($ per boe)	2012	2011
North America E&P	$11.59	$11.51
International E&P	$5.13	$4.80
Oil Sands Mining [(a)]	$45.95	$46.27

(a) Production expense per synthetic crude oil barrel (before royalties) includes production costs, shipping and handling, taxes other than income and insurance costs and excludes pre-development costs.

Marketing expenses decreased $1,154 million in 2012 from the prior year, consistent with the decreases in marketing revenues discussed above.

Exploration expenses were $65 million higher in 2012 than in 2011, primarily due to larger non-cash unproved property impairments. Unproved property impairments in 2012 related to Marcellus, Eagle Ford and Indonesia. The following table summarizes the components of exploration expenses.

(In millions)	2012	2011
Unproved property impairments	$227	$79
Dry well costs	230	278
Geological and geophysical	135	124
Other	114	160
Total exploration expenses	$706	$641

Depreciation, depletion and amortization increased $214 million in 2012 from the prior year. Our segments apply the units-of-production method to the majority of their assets; therefore, the previously discussed increases in North America E&P and International E&P sales volumes generally result in similar changes in DD&A. There was no depletion of our Alaska assets for much of 2012 because they were held for sale, which partially offset the DD&A increase.

The DD&A rate (expense per boe), which is impacted by changes in reserves and capitalized costs, can also cause changes in our DD&A. The decreases in both the North America E&P and International E&P DD&A rates in 2012 compared to 2011 were primarily due to proved reserve additions.

The following table provides DD&A rates for each segment:

($ per boe)	2012	2011
North America E&P	$23.45	$25.15
International E&P	$8.08	$9.70
Oil Sands Mining	$12.57	$12.43

Impairments in 2012 primarily related to the Ozona development in the Gulf of Mexico and to our Powder River Basin asset in Wyoming. Impairments in 2011 primarily related to the Droshky development in the Gulf of Mexico and an intangible asset for an LNG delivery contract at Elba Island. See Item 8. Financial Statements and Supplementary Data - Note 15 to the consolidated financial statements for information about these impairments.

Taxes other than income include production, severance and ad valorem taxes in the United States, which tend to increase or decrease in relation to sales volumes and revenues, and increased $55 million in 2012 from 2011. With the increase in revenues related to higher sales volumes, production and severance taxes increased. In addition, ad valorem taxes are higher because the value of our U.S. assets increased with the acquisitions in the Eagle Ford shale.

Net interest and other increased $112 million in 2012 from 2011 primarily due to lower capitalized interest in 2012. See Item 8. Financial Statements and Supplementary Data - Note 9 to the consolidated financial statements for more detailed information.

Loss on early extinguishment of debt relates to debt retirements in February and March of 2011.

Provision for income taxes increased $1,791 million in 2012 from 2011 primarily due to the increase in pretax income from continuing operations, including the impact of the resumption of sales in Libya in the first quarter of 2012. The following is an analysis of the effective income tax rates for 2012 and 2011:

	2012		2011	
Statutory rate applied to income from continuing operations before income taxes	35	%	35	%
Effects of foreign operations, including foreign tax credits	18		6	
Change in permanent reinvestment assertion	—		5	
Adjustments to valuation allowances	21		14	
Tax law changes	—		1	
Effective income tax rate on continuing operations	74	%	61	%

The effective income tax rate is influenced by a variety of factors including the geographic sources of income and the relative magnitude of these sources of income. 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 appears in the "Corporate and other unallocated items" shown in the reconciliation of segment income to net income below.

Effects of foreign operations – The effects of foreign operations on our effective tax rate increased in 2012 as compared to 2011, primarily due to the resumption of sales in Libya in the first quarter of 2012, where the statutory 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 2012 and 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 those years.

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

Discontinued operations is presented net of tax, and reflects our downstream business that was spun off June 30, 2011 and our Angola business which we agreed to sell in 2013. See Item 8. Financial Statements and Supplementary Data – Notes 3 and 6 to the consolidated financial statements for additional information.

Segment Results: 2012 compared to 2011

Segment income for 2012 and 2011 is summarized and reconciled to net income in the following table.

(In millions)	2012	2011
North America E&P	$382	$392
International E&P	1,660	1,991
Oil Sands Mining	171	261
Segment income	2,213	2,644
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(475)	(359)
Unrealized gain on crude oil derivative instruments	34	—
Net gain on dispositions	72	45
Impairments	(231)	(195)
Loss on early extinguishment of debt	—	(176)
Tax effect of subsidiary restructuring	—	(122)
Deferred income tax items	—	(61)
Water abatement - Oil Sands	—	(48)
Eagle Ford transaction costs	—	(10)
Income from continuing operations	1,613	1,718
Discontinued operations	(31)	1,228
Net income	$1,582	$2,946

North America E&P segment income decreased $10 million in 2012 compared to 2011. The decrease is largely due to lower liquid hydrocarbon price realizations and increased exploration expenses due to non-cash unproved property impairments, partially offset by higher liquid hydrocarbon net sales volumes primarily in the Eagle Ford and Bakken.

International E&P segment income decreased $331 million in 2012 compared to 2011. The decrease included lower earnings in the U.K. and E.G., partially offset by higher earnings in Libya. Also, in 2011 we were not in an excess foreign tax credit position for the entire year as we were in 2012.

Oil Sands Mining segment income decreased $90 million in 2012 compared to 2011. The decrease is primarily due to lower synthetic crude oil price realizations partially offset by higher net sales volumes.

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

Cash Flows

Net cash provided by continuing operations was $5,091 million in 2013 compared to $4,036 million in 2012 and $5,441 million in 2011. The $1,055 million increase in 2013 primarily reflects the impact of increased North America E&P liquid hydrocarbon net sales volumes on operating income. The $1,405 million decrease in 2012 was primarily the result of working capital changes related to the 2012 ramp-up of operations in the Eagle Ford and Libya along with the timing of tax payments.

Net cash used in investing activities related to continuing operations totaled $4,294 million in 2013 compared to $5,092 million in 2012 and $6,865 million in 2011. Significant investing activities include acquisitions, additions to property, plant and equipment and asset disposals.

Acquisitions in 2013, 2012 and 2011 included proved and unproved assets in the Eagle Ford. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements for further information about the transactions. In recent years, the focus of most of our capital spending has been in our North America E&P segment related to unconventional resource plays like the Eagle Ford, Bakken and Oklahoma resource basins.

Disposals of assets totaled $450 million, $467 million, and $518 million in 2013, 2012 and 2011. In 2013, net proceeds were primarily related to the sales of our interests in Alaska, the Neptune gas plant, and the DJ Basin. In 2012, net proceeds were primarily from the sales of our interests in several Gulf of Mexico crude oil pipeline systems, a sell-down of our interests in the Harir and Safen blocks in the Kurdistan Region of Iraq, and the final collection of proceeds on a 2009 asset sale. Several sales of non-core assets and acreage sell-downs in 2011 resulted in net proceeds of $518 million. 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 $1,162 million in 2013, provided cash of $1,600 million in 2012 and used cash of $5,211 million in 2011. Debt repayments of $182 million, $145 million, and $2,877 million occurred in 2013, 2012 and 2011. Purchases of common stock used $500 million in cash during 2013 and $300 million in 2011. Dividend payments were uses of cash in every year. Sources of cash in 2012 included the issuance of a net $200 million in commercial paper and $2 billion in senior notes. In connection with the spin-off, we distributed $1,622 million to MPC in the second quarter of 2011.

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 committed revolving credit facility and sales of non-strategic assets. Our working capital requirements are supported by these sources and we may issue commercial paper backed by our $2.5 billion revolving credit facility to meet short-term cash requirements. We issued $10,870 million and repaid $10,935 million of commercial paper in 2013, leaving a balance of $135 million outstanding at December 31, 2013. Because of the alternatives available to us as discussed above and access to capital markets through the shelf registration discussed below, 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, 2013, we had $6,462 million in long-term debt outstanding, $68 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, 2013, we had no borrowings against our revolving credit facility and had $135 million in commercial paper outstanding under our commercial paper program, which is backed by the revolving credit facility. See Item 8. Financial Statements and Supplementary Data – Note 17 to the consolidated financial statements for a description of the revolving credit facility.

2014 Asset Disposals

The sale of our interest in Angola Block 31 closed in February 2014 for proceeds of $1.5 billion before closing adjustments. These proceeds will be used to repurchase $500 million of common stock with the remainder to be used for general corporate purposes. The sale of our interest in Angola Block 32 for proceeds of $590 million before closing adjustments is expected to close in the first quarter of 2014.

Shelf Registration

We are a "well-known seasoned issuer" for purposes of SEC rules, thereby allowing us to use a universal shelf registration statement should we choose to issue and sell various types of equity and debt securities. Beginning in the first quarter of 2013, we changed our reportable segments and subsequently have recast all periods presented in this Annual Report on Form 10-K to reflect these new segments in our consolidated financial statements. We expect to update and file our universal shelf registration statement shortly after the filing of this Annual Report on Form 10-K with the SEC.

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 25 percent at December 31, 2013 and 2012.

(Dollars in millions)	2013	2012
Commercial paper	$135	$200
Long-term debt due within one year	68	184
Long-term debt	6,394	6,512
Total debt	$6,597	$6,896
Cash	$264	$684
Equity	$19,344	$18,283
Calculation:		
Total debt	$6,597	$6,896
Minus cash	264	684
Total debt minus cash	6,333	6,212
Total debt	6,597	6,896
Plus equity	19,344	18,283
Minus cash	264	684
Total debt plus equity minus cash	$25,677	$24,495
Cash-adjusted debt-to-capital ratio	25 %	25 %

Capital Requirements

Capital Spending

Our approved capital, investment and exploration spending budget for 2014 is $5,882 million. Additional details related to this 2014 budget are discussed in Outlook.

Share Repurchase Program

In 2013, our Board of Directors increased the authorization for repurchases of our common stock by $1.2 billion, bringing the total authorized to $6.2 billion of which $2.5 billion is remaining. As of December 31, 2013, we had repurchased 92 million common shares at a cost of $3,722 million, with 14 million shares acquired at a cost of $500 million during the third quarter of 2013, 12 million shares acquired at a cost of $300 million in the third quarter of 2011 and 66 million shares purchased for $2,922 million prior to the spin-off of our downstream business. As previously discussed, a portion of the proceeds from the sale of our interest in Angola Block 31 will be used to repurchase $500 million of common stock. Purchases under the repurchase 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.

Other Expected Cash Outflows

We plan to make contributions of up to $77 million to our funded pension plans during 2014, and $11 million of that amount was paid in January 2014. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $74 million and $19 million in 2014. As of December 31, 2013, $135 million of commercial paper and $68 million of our long-term debt is due in the next twelve months.

Dividends of $508 million were paid during 2013 reflecting quarterly dividends of $0.17 per share in the first two quarters of the year and $0.19 per share in the last two quarters for a per share increase of 12 percent. On January 29, 2014, we announced that our Board of Directors had declared a dividend of $0.19 cents per share on Marathon Oil common stock, payable March 10, 2014, to stockholders of record at the close of business on February 19, 2014.

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 the use of proceeds from the sale of our interest in Angola Block 31, the timing and amount of repurchasing additional common stock and the timing of closing the sale of our interest in Angola Block 32. The expectations with respect to the use of proceeds from the sale of our interest in Angola Block 31 and the timing and amount of repurchasing additional common stock could be affected by changes in the prices and demand for liquid hydrocarbons and natural gas, actions of competitors, disruptions or interruptions of our exploration or production operations, unforeseen hazards such as weather conditions or acts of war or terrorist acts and other operating and economic considerations. The sale of our interest in Angola Block 32 is subject to customary closing conditions. The discussion of liquidity above also contains forward-looking statements regarding planned funding of pension plans, which are based on current expectations, estimates and projections and are not guarantees of actual performance.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2013.

(In millions)	Total	2014	2015-2016	2017-2018	Later Years
Short and long-term debt (excludes interest)[a]	$6,572	$203	$1,068	$1,536	$3,765
Lease obligations	235	46	78	44	67
Purchase obligations:					
Oil and gas activities[b]	1,294	742	391	74	87
Service and materials contracts[c]	925	192	231	100	402
Transportation and related contracts	1,345	211	330	201	603
Drilling rigs and fracturing crews[d]	1,037	554	461	22	—
Other	237	42	57	32	106
Total purchase obligations	4,838	1,741	1,470	429	1,198
Other long-term liabilities reported in the consolidated balance sheet[e]	1,258	181	276	244	557
Total contractual cash obligations[f]	$12,903	$2,171	$2,892	$2,253	$5,587

(a) We anticipate cash payments for interest of $299 million for 2014, $596 million for 2015-2016, $520 million for 2017-2018 and $2,619 million for the remaining years for a total of $4,034 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) Some contracts may be canceled at an amount less than the contract amount. Were we to elect that option where possible at December 31, 2013 our minimum commitment would be $905 million.

(e) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2023. Also includes amounts for uncertain tax positions.

(f) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $2,096 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 E.G. Onshore E.G., 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.

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, 2013, 2012 and 2011 aggregated $119 million, $139 million, and $231 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 and future abandonment liabilities.

Outlook

Budget

Our Board of Directors approved a capital, investment and exploration spending budget of $5,882 million for 2014, including budgeted capital expenditures of $5,777 million. Our capital, investment and exploration spending budget is broken down by reportable segment in the table below.

(In millions)	2014 Budget	Percent of Total	
North America E&P	$4,241	72	%
International E&P	1,242	21	%
Oil Sands Mining	294	5	%
Segment total	5,777	98	%
Corporate and other	105	2	%
Total capital, investment and exploration spending budget	$5,882	100	%

We continue to focus on growing profitable reserves and production worldwide. In 2014, we are accelerating drilling activity in our three key U.S. unconventional resource plays: the Eagle Ford, Bakken and Oklahoma resource basins, which account for approximately 60 percent of our budget. The majority of spending in our unconventional resource plays is intended for drilling. With an increased number of rigs in each of these areas, we plan to drill more net wells in these areas than in any previous year. We also have dedicated a portion of our capital budget in these areas to facility construction and recompletions. In our conventional assets, we will follow a disciplined spending plan that is intended to provide stable production,with approximately 23 percent of our budget allocated to the development of these assets worldwide. We also plan to either drill or participate in 8 to 10 exploration wells throughout our portfolio, with 10 percent of our budget allocated to exploration projects. For additional information about expected exploration and development activities see Item 1. Business.

The above discussion includes forward-looking statements with respect to projected spending and investment in exploration and development activities under the 2014 capital, investment and exploration spending budget, accelerated rig and drilling activity in the Eagle Ford, Bakken, and Oklahoma resource basins, and future exploratory and development drilling activity. Some factors which could potentially affect these forward-looking statements include pricing, supply and demand for liquid hydrocarbons and natural gas, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, availability of materials and labor, other risks associated with construction projects, 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. These 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 development projects 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.

Sales Volumes

We expect to increase our U.S. resource plays' net sales volumes by more than 30 percent in 2014 compared to 2013, excluding dispositions. In addition, we expect total production growth to be approximately 4 percent in 2014 versus 2013, excluding dispositions and Libya.

Acquisitions and Dispositions

Excluded from our budget are the impacts of acquisitions and dispositions not previously announced. We continually evaluate ways to optimize our portfolio through acquisitions and divestitures and exceeded our previously stated goal of divesting between $1.5 billion and $3.0 billion of assets over the period of 2011 through 2013. For the three-year period ended December 31, 2013, we closed or entered agreements for approximately $3.5 billion in divestitures, of which $2.1 billion is from the sales of our Angola assets. The sale of our interest in Angola Block 31 closed in February 2014 and the sale of our interest in Angola Block 32 is expected to close in the first quarter of 2014.

In December 2013, we announced the commencement of efforts to market our assets in the North Sea, both in the U.K. and Norway, which would simplify and concentrate our portfolio to higher margin growth opportunities and increase our production growth rate.

The above discussion includes forward-looking statements with respect to our percentage growth rate of production, production available for sale, the sale of our interest in Angola Block 32 and the possible sale of our U.K. and Norway assets. Some factors which could potentially affect our percentage growth rate of production and production available for sale include pricing, supply and demand for liquid hydrocarbons and natural gas, the amount of capital available for exploration and development, regulatory constraints, timing of commencing production from new wells, drilling rig availability, availability of materials and labor, the inability to obtain or delay in obtaining necessary government or third-party approvals and permits, unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto, and other geological, operating and economic considerations. 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 difficult to predict. The timing of closing the sale of our interest in Block 32 is subject to customary closing conditions. The possible sale of our U.K. and Norway assets is subject to the identification of one or more buyers, successful negotiations, board approval and execution of definitive agreements. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

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.

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. For additional information see Item 8. Financial Statements and Supplementary Data – Note 25 to the consolidated financial statements.

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 costs 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.

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

Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the U.S. 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 any of our segments. The following table illustrates, on average, the sensitivity of each segment's units-of-production DD&A per boe and pretax income to a hypothetical five percent change in 2013 proved reserves based on 2013 production.

	Impact of a Five Percent Increase in Proved Reserves		Impact of a Five Percent Decrease in Proved Reserves	
(In millions, except per boe)	DD&A per boe	Pretax Income	DD&A per boe	Pretax Income
North America E&P	$(1.25)	$92	$1.38	$(101)
International E&P	(0.35)	30	0.38	(33)
Oil Sands Mining	$(0.46)	$7	$0.73	$(11)

Asset Retirement Obligations

We have material legal, regulatory and contractual obligations to remove and dismantle long-lived assets and to restore land or seabed at the end of oil and gas production operations, including bitumen mining operations. A liability equal to the fair value of such obligations and a corresponding capitalized asset retirement cost are recognized on the balance sheet in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be made. The capitalized asset retirement cost is depreciated using the units-of-production method and the discounted liability is accreted over the period until the obligation is satisfied, the impacts of which are recognized as DD&A in the consolidated statements of income. In many cases, the satisfaction and subsequent discharge of these liabilities is projected to occur many years, or even decades, into the future. Furthermore, the legal, regulatory and contractual requirements often do not provide specific guidance regarding removal practices and the criteria that must be fulfilled when the removal and/or restoration event actually occurs.

Estimates of retirement costs are developed for each property based on numerous factors, such as the scope of the dismantlement, timing of settlement, interpretation of legal, regulatory and contractual requirements, type of production and processing structures, depth of water (if applicable), reservoir characteristics, depth of the reservoir, market demand for equipment, currently available dismantlement and restoration procedures and consultations with construction and engineering professionals. Inflation rates and credit-adjusted-risk-free interest rates are then applied to estimate the fair values of the obligations. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related asset balance. See Item 8. Financial Statements and Supplementary Data – Note 18 to the consolidated financial statements for disclosures regarding our asset retirement obligation estimates.

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 obligations that must be assessed, the number of underlying assumptions and the wide range of possible assumptions.

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, or range of present values, 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 do 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. 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; 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 in use 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 our North America E&P and International E&P assets and at the project level for OSM assets. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition 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 present value of expected 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 reserve categories such that the combined volumes represent the most likely expectation of recovery.
- Expected timing of production. Production forecasts are the outcome of engineer studies which estimate reserves, as well as expected capital development programs. 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 upon a combination of 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 2013, 2012 and 2011, we completed several business combinations in the Eagle Ford, the purchase prices of which were 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. Fair value measurements for all our derivative instruments are based on observable market-based inputs that are corroborated by market data and are 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 a combination of reserve categories 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 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 U.S. pension plans and our other U.S. postretirement benefit plans 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 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 issuances within each defined maturity group.

Of the assumptions used to measure obligations and estimated annual net periodic benefit cost as of December 31, the discount rate has the most significant effect on the periodic benefit cost reported for the plans. The hypothetical impacts of a 0.25 percent change in the discount rates of 4.28 percent for our U.S. pension plans and 4.85 percent for our other U.S. postretirement benefit plans is summarized in the table below:

	Impact of a 0.25 Percent Increase in Discount Rate	Impact of a 0.25 Percent Decrease in Discount Rate

(In millions)	Obligation	Expense	Obligation	Expense
U.S. pension plans	$(38)	$(4)	$40	$4
Other U.S. postretirement benefit plans	$(7)	$—	$8	$—

The asset rate of return assumption for the funded U.S. plan considers the plan's asset mix (currently targeted at approximately 55 percent equity and high-yield bonds and 45 percent other fixed income securities), 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 6.75 percent asset rate of return assumption by 0.25 would not have a significant impact on our defined benefit pension expense. Effective January 1, 2014, the expected long-term rate of return was changed from 7.25 percent to 6.75 percent and this change also did not have a significant impact.

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 detail