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

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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

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)]

(Dollars per boe)	North America U.S.	Canada[(b)]	Total	Africa E.G.	Other[(c)]	Total	Europe 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:

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($ 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.

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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 detailed information about the assumptions used to calculate the components of our annual defined benefit pension and other postretirement plan expense, as well as the obligations and accumulated other comprehensive income reported on the consolidated balance sheets.

Contingent Liabilities

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

We generally record losses related to these types of contingencies as other operating expense or general and administrative expense in the consolidated statements of income, except for tax contingencies unrelated to income taxes, which are recorded as taxes other than income. For additional information on contingent liabilities, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Management’s Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

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

Accounting Standards Not Yet Adopted

In June 2013, the FASB ratified the Emerging Issues Task Force consensus which requires that an unrecognized tax benefit (or a portion thereof) be presented as a reduction to a deferred tax asset for an available net operating loss carryforward, a similar tax loss or tax credit carryforward. This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied prospectively to unrecognized tax benefits that exist as of the effective date. Early adoption and retrospective application are permitted. Adoption of this accounting standards update will not have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within U.S. GAAP. An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of 1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and 2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption is permitted. Adoption of this accounting standards update will not have a significant impact on our consolidated results of operations, financial position or cash flows.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks related to the volatility of liquid hydrocarbon, natural gas and synthetic crude oil prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. We are also exposed to market risks related to changes in interest rates and foreign currency exchange rates. We employ various strategies, including the use of financial derivative instruments, to manage the risks related to these fluctuations.

We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price or rate changes related to the underlying commodity or financial transaction.

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

See Item 8. Financial Statements and Supplementary Data – Notes 15 and 16 to the consolidated financial statements for more information about the fair value measurement of our derivatives, the amounts recorded in our consolidated balance sheets and statements of income and the related notional amounts.

Commodity Price Risk

Our strategy is to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. However, management will periodically protect prices on forecasted sales, as deemed appropriate. We use a variety of commodity derivative instruments, including futures, forwards, swaps and combinations of options, as part of an overall program to manage commodity price risk in our different businesses. Our consolidated results for 2013 and 2012 were impacted by crude oil derivatives related to a portion of our forecast North America E&P crude oil sales, all of which had terms that ended in December 2013.

We regularly use commodity derivative instruments in the North America E&P segment to manage natural gas price risk. Examples would include the hedging of storage and transportation assets, and when appropriate, managing equity price exposure.

Interest Rate Risk

We are impacted by interest rate fluctuations which affect the fair value of certain financial instruments. We manage our exposure to interest rate movements by utilizing financial derivative instruments. The primary objective of this program is to reduce our overall cost of borrowing by managing the mix of fixed and floating interest rate debt in our portfolio. As of December 31, 2013, we had multiple interest rate swap agreements with a total notional of $900 million designated as fair value hedges, which effectively results in an exchange of existing obligations to pay fixed interest rates for obligations to pay floating rates.

At December 31, 2013, our portfolio of long-term debt was substantially comprised of fixed rate instruments. Therefore, the fair value of the portfolio is relatively sensitive to interest rate fluctuations. Our sensitivity to interest rate declines and corresponding increases in the fair value of our debt portfolio unfavorably affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices above carrying value.

Sensitivity analysis of the incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of December 31, 2013, is provided in the following table.

(In millions)	Fair Value		Incremental Change in Fair Value	
Financial assets (liabilities): [(a)]				
Interest rate swap agreements	$8	[(b)]	$4	
Long-term debt, including amounts due within one year	$(6,922	) [(b)(c)]	$(234	)

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

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

[(c)] Excludes capital leases.

Foreign Currency Exchange Rate Risk

We may manage our exposure to foreign currency exchange rates by utilizing forward and option contracts. The primary objective of this program is to reduce our exposure to movements in foreign currency exchange rates by locking in such rates. As of December 31, 2013, our foreign currency forwards had a notional of 2,387 million

Norwegian Kroner, which served as a hedge of our current Norwegian tax liability. The incremental change in the fair value of foreign currency derivative contracts of a hypothetical 10 percent change in exchange rates at December 31, 2013 would be $39 million.

Counterparty Risk

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

Safe Harbor

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

Item 8. Financial Statements and Supplementary Data

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Management’s Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

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

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

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

/s/ Lee M. Tillman	/s/ John R. Sult
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer

Management’s Report on Internal Control over Financial Reporting

To the Stockholders of Marathon Oil Corporation:

Marathon Oil’s management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13(a) – 15(f) under the Securities Exchange Act of 1934). An evaluation of the design and effectiveness of our internal control over financial reporting, based on the original 1992 framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on the results of this evaluation, Marathon Oil’s management concluded that its internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of Marathon Oil’s internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Lee M. Tillman	/s/ John R. Sult
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm
To the Stockholders of Marathon Oil Corporation:
In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Marathon Oil Corporation and its subsidiaries (the "Company") at December 31, 2013, and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in the original 1992 framework in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Houston, Texas
February 28, 2014

MARATHON OIL CORPORATION
Consolidated Statements of Income

(In millions, except per share data)	2013	2012	2011
Revenues and other income:			
Sales and other operating revenues, including related party	$12,419	$12,963	$10,750
Marketing revenues	2,082	2,729	3,919
Income from equity method investments	423	370	462
Net gain (loss) on disposal of assets	(29)	127	103
Other income	64	32	48
Total revenues and other income	14,959	16,221	15,282
Costs and expenses:			
Production	2,331	2,202	1,951
Marketing, including purchases from related parties	2,072	2,744	3,898
Other operating	439	425	533
Exploration	988	706	641
Depreciation, depletion and amortization	2,790	2,477	2,263
Impairments	96	371	310
Taxes other than income	352	248	193
General and administrative	687	699	663
Total costs and expenses	9,755	9,872	10,452
Income from operations	5,204	6,349	4,830
Net interest and other	(274)	(219)	(107)
Loss on early extinguishment of debt	—	—	(279)
Income from continuing operations before income taxes	4,930	6,130	4,444
Provision for income taxes	3,337	4,517	2,726
Income from continuing operations	1,593	1,613	1,718
Discontinued operations	160	(31)	1,228
Net income	$1,753	$1,582	$2,946
Per Share Data			
Basic:			
Income from continuing operations	$2.26	$2.28	$2.42
Discontinued operations	$0.23	$(0.04)	$1.73
Net income	$2.49	$2.24	$4.15
Diluted:			
Income from continuing operations	$2.24	$2.27	$2.41
Discontinued operations	$0.23	$(0.04)	$1.72
Net income	$2.47	$2.23	$4.13
Dividends	$0.72	$0.68	$0.80
Weighted average shares:			
Basic	705	706	710
Diluted	709	710	714

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income

(In millions)	2013	2012	2011
Net income	$1,753	$1,582	$2,946
Other comprehensive income (loss)			
Postretirement and postemployment plans			
Change in actuarial loss and other	296	(97)	16
Income tax benefit (provision)	(112)	35	20
Postretirement and postemployment plans, net of tax	184	(62)	36
Derivative hedges			
Net unrecognized gain	1	1	9
Income tax provision	—	—	(4)
Derivative hedges, net of tax	1	1	5
Foreign currency translation and other			
Unrealized gain (loss)	(3)	1	(1)
Income tax benefit (provision)	1	(3)	—
Foreign currency translation and other, net of tax	(2)	(2)	(1)
Other comprehensive income (loss)	183	(63)	40
Comprehensive income	$1,936	$1,519	$2,986

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets

(In millions, except per share data)	December 31, 2013	2012
Assets		
Current assets:		
Cash and cash equivalents	$264	$684
Receivables	2,134	2,418
Inventories	364	361
Other current assets	213	299
Total current assets	2,975	3,762
Equity method investments	1,201	1,279
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $21,895 and $19,266	28,145	28,272
Goodwill	499	525
Other noncurrent assets	2,800	1,468
Total assets	$35,620	$35,306
Liabilities		
Current liabilities:		
Commercial paper	$135	$200
Accounts payable	2,206	2,324
Payroll and benefits payable	240	217
Accrued taxes	1,445	1,983
Other current liabilities	239	173
Long-term debt due within one year	68	184
Total current liabilities	4,333	5,081
Long-term debt	6,394	6,512
Deferred tax liabilities	2,492	2,432
Defined benefit postretirement plan obligations	604	856
Asset retirement obligations	2,009	1,749
Deferred credits and other liabilities	444	393
Total liabilities	16,276	17,023
Commitments and contingencies		
Stockholders' Equity		
Preferred stock - no shares issued or outstanding (no par value, 26 million shares authorized)	—	—
Common stock:		
Issued – 770 million and 770 million shares (par value $1 per share, 1.1 billion shares authorized)	770	770
Securities exchangeable into common stock – no shares issued or outstanding (no par value, 29 million shares authorized)	—	—
Held in treasury, at cost – 73 million and 63 million shares	(2,903)	(2,560)
Additional paid-in capital	6,592	6,616
Retained earnings	15,135	13,890
Accumulated other comprehensive loss	(250)	(433)
Total stockholders' equity	19,344	18,283
Total liabilities and stockholders' equity	$35,620	$35,306

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

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

(In millions)	2013	2012	2011
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income	$1,753	$1,582	$2,946
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations	(160)	31	(1,228)
Loss on early extinguishment of debt	—	—	279
Deferred income taxes	(60)	(224)	(193)
Depreciation, depletion and amortization	2,790	2,477	2,263
Impairments	96	371	310
Pension and other postretirement benefits, net	45	(31)	64
Exploratory dry well costs and unproved property impairments	798	457	357
Net (gain) loss on disposal of assets	29	(127)	(103)
Equity method investments, net	12	11	47
Changes in:			
Current receivables	277	(502)	9
Inventories	(16)	(32)	33
Current accounts payable and accrued liabilities	(616)	71	489
All other operating, net	143	(48)	168
Net cash provided by continuing operations	5,091	4,036	5,441
Net cash provided by (used in) discontinued operations	179	(19)	1,083
Net cash provided by operating activities	5,270	4,017	6,524
Investing activities:			
Acquisitions, net of cash acquired	(74)	(1,033)	(4,470)
Additions to property, plant and equipment	(4,766)	(4,593)	(2,986)
Disposal of assets	450	467	518
Investments - return of capital	61	57	59
Investing activities of discontinued operations	(227)	(347)	(802)
All other investing, net	35	10	14
Net cash used in investing activities	(4,521)	(5,439)	(7,667)
Financing activities:			
Commercial paper, net	(65)	200	—
Borrowings	—	1,997	—
Debt issuance costs	—	(21)	—
Debt repayments	(182)	(145)	(2,877)
Purchases of common stock	(500)	—	(300)
Dividends paid	(508)	(480)	(567)
Financing activities of discontinued operations	—	—	2,916
Distribution in spin-off	—	—	(1,622)
All other financing, net	93	49	155
Net cash provided by (used in) financing activities	(1,162)	1,600	(2,295)
Effect of exchange rate changes on cash	(7)	13	(20)
Net increase (decrease) in cash and cash equivalents	(420)	191	(3,458)
Cash and cash equivalents at beginning of period	684	493	3,951
Cash and cash equivalents at end of period	$264	$684	$493

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

MARATHON OIL CORPORATION
Consolidated Statements of Stockholders' Equity

(In millions)	Total Equity of Marathon Oil Stockholders Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total Equity
January 1, 2011 Balance	$—	$770	$—	$(2,665)	$6,756	$19,907	$(997)	$—	$23,771
Shares issued - stock-based compensation	—	—	—	257	(85)	—	—	—	172
Shares repurchased	—	—	—	(308)	—	—	—	—	(308)
Stock-based compensation	—	—	—	—	4	—	—	—	4
Net income	—	—	—	—	—	2,946	—	—	2,946
Other comprehensive income	—	—	—	—	—	—	40	—	40
Dividends paid	—	—	—	—	—	(567)	—	—	(567)
Purchase of subsidiary shares from non-controlling interest	—	—	—	—	—	—	—	7	7
Spin-off of downstream	—	—	—	—	5	(9,498)	587	—	(8,906)
December 31, 2011 Balance	$—	$770	$—	$(2,716)	$6,680	$12,788	$(370)	$7	$17,159
Shares issued - stock-based compensation	—	—	—	164	(75)	—	—	—	89
Shares repurchased	—	—	—	(8)	—	—	—	—	(8)
Stock-based compensation	—	—	—	—	22	—	—	—	22
Net income	—	—	—	—	—	1,582	—	—	1,582
Other comprehensive loss	—	—	—	—	—	—	(63)	—	(63)
Dividends paid	—	—	—	—	—	(480)	—	—	(480)
Purchase of subsidiary shares from non-controlling interest	—	—	—	—	—	—	—	(7)	(7)
Other	—	—	—	—	(11)	—	—	—	(11)
December 31, 2012 Balance	$—	$770	$—	$(2,560)	$6,616	$13,890	$(433)	$—	$18,283
Shares issued - stock-based compensation	—	—	—	170	(44)	—	—	—	126
Shares repurchased	—	—	—	(513)	—	—	—	—	(513)
Stock-based compensation	—	—	—	—	20	—	—	—	20
Net income	—	—	—	—	—	1,753	—	—	1,753
	—	—	—	—	—	—	183	—	183

Other comprehensive income									
Dividends paid	—	—	—	—	—	(508)	—	—	(508)
December 31, 2013 Balance	$—	$770	$—	$(2,903)	$6,592	$15,135	$(250)	$—	$19,344

(Shares in millions)	Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock
January 1, 2011 Balance	—	770	—	60
Shares issued - stock-based compensation	—	—	—	(6)
Shares repurchased	—	—	—	12
December 31, 2011 Balance	—	770	—	66
Shares issued - stock-based compensation	—	—	—	(3)
December 31, 2012 Balance	—	770	—	63
Shares issued - stock-based compensation	—	—	—	(4)
Shares repurchased	—	—	—	14
December 31, 2013 Balance	—	770	—	73

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

MARATHON OIL CORPORATION
Notes to Consolidated Financial Statements

1. Summary of Principal Accounting Policies

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

Principles applied in consolidation – These consolidated financial statements include the accounts of our majority-owned, controlled subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

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

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

Discontinued operations – Disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations unless otherwise stated. Due to the agreements entered in 2013 to sell our Angola assets (see Note 6), the corresponding results of operations and cash flows have been classified as discontinued operations for all presented periods. As a result of the spin-off of our downstream business in 2011 (see Note 3), the related results of operations and cash flows have been classified as discontinued operations for all periods prior to the spin-off.

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

Reclassifications – Beginning in 2013, we changed the presentation of our consolidated statements of income, primarily to present additional details of revenues and expenses and to classify certain expenses more consistently with our peer group of independent exploration and production companies. To effect these changes, reclassifications of previously reported amounts were made and are reflected in these consolidated financial statements. As a result of the reclassifications, general and administrative expenses for 2012 and 2011 increased by $144 million and $119 million which primarily includes certain costs associated with operations support and operations management. Offsetting reductions are reflected in production, other operating and exploration expenses and taxes other than income.

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

Revenue recognition – Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. We follow the sales method of accounting for crude oil and natural gas production imbalances and would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. Imbalances have not been significant in the periods presented.

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

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

Accounts receivable – The majority of our receivables are from joint interest owners in properties we operate or from purchasers of commodities, both of which are recorded at invoiced amounts and do not bear interest. We often have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We conduct credit reviews of commodity purchasers prior to making commodity sales to new customers or increasing credit for existing customers. Based on these reviews, we may require a standby letter of credit or a financial guarantee. Uncollectible accounts receivable are reserved against the allowance for uncollectible accounts when it is determined the receivable will not be collected and the amount of any reserve may be reasonably estimated.

Inventories – Inventories are carried at the lower of cost or market value. The majority of our inventories are recorded at average cost. The last-in, first-out ("LIFO") method is used for our U.S. crude oil and natural gas inventories.

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

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

Cash flow hedges – We may use foreign currency forwards and options to manage foreign currency risk associated with anticipated transactions and designate them as cash flow hedges. No such derivatives were outstanding at December 31, 2013 and 2012. The effective portion of changes in fair value is recognized in other comprehensive income ("OCI") and is reclassified to net income when the underlying forecasted transaction is recognized in net income. Any ineffective portion is recognized in net interest and other as it occurs. For a discontinued cash flow hedge, prospective changes in the fair value of the derivative are recognized in net income. The accumulated gain or loss recognized in OCI at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in OCI is immediately reclassified into net income.

We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings and designate them as cash flow hedges. No such derivatives were outstanding at December 31, 2013 and 2012.

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

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

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

Fair value transfer – We recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. When significant transfers occur, they are disclosed in Note 15 to the consolidated financial statements.

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

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

Depreciation, depletion and amortization – Capitalized costs to acquire oil and natural gas properties, which include bitumen mining and upgrading facilities, are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities are depreciated on a straight-line basis over their estimated useful lives which range from 3 to 40 years.

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

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

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

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

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

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

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

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

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Deferred income taxes – Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. We routinely assess the realizability of our deferred tax assets based on several interrelated factors 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. These factors include our expectation to generate sufficient future taxable income including future foreign source income, tax credits, operating loss carryforwards and management's intent regarding the permanent reinvestment of the income from certain foreign subsidiaries.

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

The fair value of our restricted stock awards and common stock units is determined based on the market value of our common stock on the date of grant. Unearned stock-based compensation is charged to stockholders' equity when restricted stock awards are granted.

The fair value of our stock-based performance units is estimated using the Monte Carlo simulation method. Since these awards are settled in cash at the end of a defined performance period, they are classified as a liability and are re-measured quarterly until settlement.

Our stock-based compensation expense is recognized based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods.

2. Accounting Standards

Not Yet Adopted

In June 2013, the FASB ratified the Emerging Issues Task Force consensus which requires that an unrecognized tax benefit (or a portion thereof) be presented as a reduction to a deferred tax asset for an available net operating loss carryforward, a similar tax loss or tax credit carryforward. This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied prospectively to unrecognized tax benefits that exist as of the effective date. Early adoption and retrospective application are permitted. Adoption of this accounting standards update will not have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within U.S. GAAP. An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of 1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and 2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This accounting standards update is effective for us beginning in the first quarter of 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption is permitted. Adoption of this accounting standards update will not have a significant impact on our consolidated results of operations, financial position or cash flows.

Recently Adopted

In February 2013, an accounting standards update was issued to improve the reporting of reclassifications out of accumulated other comprehensive income. This standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This accounting standards update was effective for us beginning the first quarter of 2013 and we present the required disclosures in Note 22. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In December 2011, an accounting standards update designed to enhance disclosures about offsetting assets and liabilities was issued. Further clarification limiting the scope of these disclosures to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions was issued in January 2013. The disclosures are intended to enable financial statement users to evaluate the effect or potential effect of netting arrangements on an entity's financial position. Entities are required to disclose both gross information and net information about in-scope financial instruments that are either offset in the statement of financial position or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. The accounting standards update was effective for us beginning the first quarter of 2013 and we include the required disclosures in Note 16. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In September 2011, the FASB amended accounting standards to simplify how entities test goodwill for impairment. The amendment reduces complexity by allowing an entity the option to make a qualitative evaluation of whether it is necessary to perform the two-step goodwill impairment test. Adoption of this amendment in 2012 did not have a significant impact on our consolidated results of operations, financial position or cash flows.

The FASB amended the reporting standards for comprehensive income in June 2011 to eliminate the option to present the components of OCI as part of the statement of changes in stockholders' equity. All non-owner changes in stockholders' equity are required to be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of OCI, and total comprehensive income. The presentation of items that are reclassified from OCI to net income on the income statement is also required. The amendments did not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. The amendments were effective for us beginning with the first quarter of 2012, except for the presentation of reclassifications, which was deferred and addressed in the February 2013 accounting standards update discussed above. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In May 2011, the FASB issued an update amending the accounting standards for fair value measurement and disclosure, resulting in common principles and requirements under U.S. GAAP and IFRS. The amendments change the wording used to describe certain of the U.S. GAAP requirements either to clarify the intent of existing requirements, to change measurement or expand disclosure principles or to conform to the wording used in IFRS. Adoption of the amendments in 2012 did not have a significant impact on our consolidated results of operations, financial position or cash flows. To the extent they were necessary, we made the expanded disclosures in Notes 15 and 16.

3. Spin-off of 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. On June 30, 2011, stockholders of record as of 5:00 p.m. Eastern Daylight Savings time on June 27, 2011 (the "Record Date") received one common share of MPC stock for every two common shares of Marathon stock held as of the Record Date.

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

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

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

The results of operations of our downstream business have been reported as discontinued operations for 2011. The table below shows selected financial information reported in discontinued operations related to the spin-off.

(In millions)	2011
Revenues applicable to discontinued operations	$38,602
Pretax income from discontinued operations	$2,012

4. Variable Interest Entities

The owners of the AOSP, in which we hold a 20 percent undivided interest, contracted with a wholly owned subsidiary of a publicly traded Canadian limited partnership ("Corridor Pipeline") to provide materials transportation capabilities among the Muskeg River and Jackpine mines, the Scotford upgrader and markets in Edmonton. The contract, originally signed in 1999 by a company we acquired, allows each holder of an undivided interest in the AOSP to ship materials in accordance with its undivided interest. Costs under this contract are accrued and recorded on a monthly basis, with a $3 million current liability recorded at December 31, 2013, consistent with December 31, 2012. Under this agreement, the AOSP absorbs all of the operating and capital costs of the pipeline. Currently, no third-party shippers use the pipeline. Should shipments be suspended, by choice or due to force majeure, we remain responsible for the portion of the payments related to our undivided interest for all remaining periods. The contract expires in 2029; however, the shippers can extend its term perpetually. This contract qualifies as a variable interest contractual arrangement and the Corridor Pipeline qualifies as a variable interest entity ("VIE"). We hold a variable interest but are not the primary beneficiary because our shipments are only 20 percent of the total; therefore the Corridor Pipeline is not consolidated by Marathon Oil. Our maximum exposure to loss as a result of our involvement with this VIE is the amount we expect to pay over the contract term, which was $723 million as of December 31, 2013. The liability on our books related to this contract at any given time will reflect amounts due for the immediately previous month’s activity, which is substantially less than the maximum exposure over the contract term. We have not provided financial assistance to Corridor Pipeline and we do not have any guarantees of such assistance in the future.

5. Acquisitions

During 2013, 2012 and 2011, our business combinations related to properties acquired by our North America E&P segment in the Eagle Ford in south Texas. The pro forma impact of these transactions, individually and in the aggregate, is not material to our consolidated statements of income for any periods presented.

The fair values of assets acquired and liabilities assumed in each of these business combinations were measured primarily using an income approach, specifically utilizing a discounted cash flow analysis. The estimated fair values were based on significant inputs not observable in the market, and therefore represent Level 3 measurements. Significant inputs included estimated reserve volumes, the expected future production profile, estimated commodity prices and assumptions regarding future operating and development costs. The discount rates used in the discounted cash flow analyses were approximately 10 percent for the 2013 and 2012 transactions and 11 percent for the 2011 transaction.

2013

In July 2013, we acquired 4,800 net undeveloped acres in the Eagle Ford in a transaction valued at $97 million, including carried interest of $23 million. The transaction was accounted for as a business combination, with the entire up-front cash consideration of $74 million allocated to property, plant and equipment at the acquisition date.

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2012 & 2011

We acquired approximately 25,000 net acres in the core of the Eagle Ford during 2012. The largest transactions were the acquisitions of Paloma Partners II, LLC, which closed in the second quarter of 2012 for cash consideration of $768 million, and an acquisition of proved and unproved properties that closed in the third quarter of 2012 for cash consideration of $232 million. These transactions were accounted for as business combinations.

During the fourth quarter of 2011, we closed a series of transactions in the Eagle Ford that were accounted for as a business combination. The most significant of these transactions was the acquisition of Hilcorp Resources, LLC. The total cash consideration paid for all the transactions including approximately 167,000 net acres and a gathering system, was $4.5 billion.

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

	Closed in Quarter Ended		
(In millions)	June 30, 2012	September 30, 2012	December 31, 2011
Current assets:			
Cash	$8	$—	$—
Receivables	22	8	40
Inventories	1	—	4
Other current assets	—	—	30
Total current assets acquired	31	8	74
Property, plant and equipment	822	248	4,501
Other noncurrent assets	—	—	21
Total assets acquired	853	256	4,596
Current liabilities:			
Accounts payable	78	23	101
Other current liabilities	—	—	20
Total current liabilities assumed	78	23	121
Asset retirement obligations	7	1	5
Total liabilities assumed	85	24	126
Net assets acquired	$768	$232	$4,470

In addition, during 2011, our North America E&P segment acquired approximately 108,000 net acres in the Eagle Ford for approximately $265 million. These transactions were accounted for as asset acquisitions.

6. Dispositions

2013 - North America E&P

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 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 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 January 2013, we closed the sale of our remaining assets in Alaska, for proceeds of $195 million, subject to a six-month escrow of $50 million which was collected in July 2013. After closing adjustments were made in the second quarter of 2013, the pretax gain on this sale was $55 million.

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Assets held for sale in the December 31, 2012 consolidated balance sheet were related to the Neptune gas plant and Alaska dispositions that were pending at that date and included:

(In millions)	December 31, 2012
Other current assets	$50
Other noncurrent assets	248
Total assets	$298
Deferred credits and other liabilities	$83
Total liabilities	$83

2013 - International E&P

In the fourth quarter 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 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. Block 31 is presented as held for sale and Block 32 is reflected as unproved property in property, plant and equipment in the December 31, 2013 consolidated balance sheet (See Note 13 for discussion of the capitalized costs related to suspended wells). Our entire Angola operations are reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented.

Assets held for sale in the December 31, 2013 consolidated balance sheet were related to the Angola Block 31 disposition that was pending at that date and included:

(In millions)	December 31, 2013
Other current assets	$41
Other noncurrent assets	1,647
Total assets	$1,688
Other current liabilities	$25
Deferred credits and other liabilities	43
Total liabilities	$68

Related amounts reported in discontinued operations for 2013, 2012 and 2011 were as follows:

(In millions)	2013	2012	2011
Revenues applicable to discontinued operations	$361	$—	$—
Pretax income (loss) from discontinued operations	$247	$(17)	$(17)

2012 - North America E&P

In the third quarter of 2012, we sold approximately 5,800 net undeveloped acres in the Eagle Ford for proceeds of $9 million. A pretax loss of $18 million was recorded.

In January 2012, we closed on the sale of our interests in several Gulf of Mexico crude oil pipeline systems for proceeds of $206 million. This included our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline L.L.C., as well as certain other oil pipeline interests, including the Eugene Island pipeline system. A pretax gain of $166 million was recorded.

2012 - International E&P

In May 2012, we executed agreements to relinquish our operatorship of and participating interests in the Bone Bay and Kumawa exploration licenses in Indonesia. As a result, we reported a $36 million pretax loss on disposal of assets. Government ratification of the agreements released us from our obligations and further commitments related to these licenses.

2011 - North America E&P

In December 2011, we sold our 50 percent interest in the Burns Point gas plant, a cryogenic processing plant located in St. Mary Parish, Louisiana, for total consideration of $36 million and a pretax gain of $34 million.

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In September 2011, we sold our equity interest in an LNG processing facility in Alaska and a pretax gain on the transaction of $8 million was recorded.

In April 2011, we assigned a 30 percent undivided working interest in approximately 180,000 acres in the Niobrara shale play located within the DJ Basin of southeast Wyoming and northern Colorado for total consideration of $270 million, recording a pretax gain of $37 million. See the discussion of our 2013 disposal of the remaining interest above.

7. Income per Common Share

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

	2013		2012		2011	
(In millions, except per share data)	Basic	Diluted	Basic	Diluted	Basic	Diluted
Income from continuing operations	$1,593	$1,593	$1,613	$1,613	$1,718	$1,718
Discontinued operations	160	160	(31)	(31)	1,228	1,228
Net income	$1,753	$1,753	$1,582	$1,582	$2,946	$2,946
Weighted average common shares outstanding	705	705	706	706	710	710
Effect of dilutive securities	—	4	—	4	—	4
Weighted average common shares, including dilutive effect	705	709	706	710	710	714
Per share:						
Income from continuing operations	$2.26	$2.24	$2.28	$2.27	$2.42	$2.41
Discontinued operations	$0.23	$0.23	$(0.04)	$(0.04)	$1.73	$1.72
Net income	$2.49	$2.47	$2.24	$2.23	$4.15	$4.13

The per share calculations above exclude 5 million, 10 million and 7 million stock options in 2013, 2012 and 2011 that were antidilutive.

8. Segment Information

Beginning in 2013, we changed our reportable segments and revised our management reporting to better reflect the growing importance of United States unconventional resource plays to our business. All periods presented have been recast to reflect these new segments.

We have three reportable operating segments. Each of these segments is organized and managed based upon both geographic location and the nature of the products and services it offers:

- North America E&P ("N.A. E&P") – explores for, produces and markets liquid hydrocarbons and natural gas in North America;
- International E&P ("Int'l 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 ("OSM") – mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker ("CODM"). Segment income represents income from continuing operations excluding certain items not allocated to segments, net of income taxes, attributable to the operating segments. Our corporate and operations support general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities, net of associated income tax effects. Unrealized gains or losses on crude oil derivative

instruments, certain impairments, gains or losses on dispositions or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.
In 2013, we entered into agreements to sell our Angola assets; therefore, the Angola operations are reflected as discontinued operations and excluded from the International E&P segment in all periods presented.

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As discussed in Note 3, our downstream business was spun-off on June 30, 2011 and has been reported as discontinued operations for 2011. Sales to MPC previously reported as intersegment revenues are reported as sales and other operating revenues because such sales were expected to continue subsequent to the spin-off. These sales were $1.4 billion in the first six months of 2011.

2013 (In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$5,068	$5,827	$1,576	$(52) [c]	$12,419
Marketing revenues	1,797	267	18	—	2,082
Total revenues	6,865	6,094	1,594	(52)	14,501
Income from equity method investments	—	427	—	(4) [d]	423
Net gain (loss) on disposal of assets and other income	12	50	5	(32)	35
Production expenses	797	534	1,000	—	2,331
Marketing costs	1,796	258	18	—	2,072
Exploration expenses	725	263	—	—	988
Depreciation, depletion and amortization	1,927	621	218	24	2,790
Impairments	41	—	—	55	96
Other expenses [a]	420	239	66	401	1,126
Taxes other than income	318	7	22	5	352
Net interest and other	—	—	—	274	274
Provision (benefit) for income taxes	324	3,226	69	(282)	3,337
Segment income/Income from continuing operations	$529	$1,423	$206	$(565)	$1,593
Capital expenditures [b]	$3,649	$764	$286	$285	$4,984

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Unrealized gain (loss) on crude oil derivative instruments.
[d] EGHoldings impairment (see Note 15).

2012 (In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$3,944	$7,445	$1,521	$53 [c]	$12,963
Marketing revenues	2,451	248	30	—	2,729
Total revenues	6,395	7,693	1,551	53	15,692
Income from equity method investments	2	368	—	—	370
Net gain (loss) on disposal of assets and other income	11	30	4	114	159
Production expenses	706	500	996	—	2,202
Marketing costs	2,444	269	31	—	2,744
Exploration expenses	588	118	—	—	706
Depreciation, depletion and amortization	1,428	787	217	45	2,477
Impairments	11	—	—	360	371
Other expenses [a]	400	200	60	464	1,124
Taxes other than income	226	5	22	(5)	248
Net interest and other	—	—	—	219	219
Provision (benefit) for income taxes	223	4,552	58	(316)	4,517
Segment income/Income from continuing operations	$382	$1,660	$171	$(600)	$1,613
Capital expenditures [b]	$3,988	$489	$188	$466	$5,131

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2011 (In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$3,364	$5,851	$1,535	$—	$10,750
Marketing revenues	3,614	252	53	—	3,919
Total revenues	6,978	6,103	1,588	—	14,669
Income from equity method investments	20	442	—	—	462
Net gain (loss) on disposal of assets and other income	21	73	(17)	74	151
Production expenses	545	409	915	82	1,951
Marketing costs	3,598	247	53	—	3,898
Exploration expenses	388	253	—	—	641
Depreciation, depletion and amortization	1,191	828	196	48	2,263
Impairments	12	—	—	298	310
Other expenses [a]	494	191	46	465	1,196
Taxes other than income	182	6	17	(12)	193
Net interest and loss on early extinguishment of debt	—	—	—	386	386
Provision (benefit) for income taxes	217	2,693	83	(267)	2,726
Segment income/Income from continuing operations	$392	$1,991	$261	$(926)	$1,718
Capital expenditures [b]	$2,163	$544	$308	$384	$3,399

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

(In millions)	2013	2012	2011
United States	$6,813	$6,448	$6,978
Norway	3,183	3,714	3,563
Canada	1,594	1,551	1,588
Libya[a]	1,106	1,989	216
Other international	1,805	1,990	2,324
Total revenues	$14,501	$15,692	$14,669

[a] See Note 13 for discussion of Libya operations.

In 2013, sales to British Petroleum and its affiliates accounted for approximately 11 percent of our total revenues. In 2012, Statoil, the purchaser of the majority of our Libyan crude oil, accounted for approximately 15 percent of our total revenues, while sales to Shell Oil and its affiliates accounted for approximately 12 percent of total revenues. In 2011, our sales to MPC accounted for approximately 18 percent of total revenues.

Revenues by product line were:

(In millions)	2013	2012	2011
Liquid hydrocarbons	$11,932	$12,983	$11,778
Natural gas	937	1,052	1,203
Synthetic crude oil	1,542	1,409	1,442
Other	90	248	246
Total revenues	$14,501	$15,692	$14,669

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

	December 31,	
(In millions)	2013	2012
United States	$14,635	$13,677
Canada	9,794	9,693
Norway	977	987
Equatorial Guinea	1,977	2,081
Other international	1,963	3,113
Total long-lived assets	$29,346	$29,551

9. Other Items

Net interest and other

(In millions)	2013	2012	2011
Interest:			
Interest income	$6	$13	$12
Interest expense[a]	(307)	(244)	(228)
Income on interest rate swaps	9	7	10
Interest capitalized	21	12	103
Total interest	(271)	(212)	(103)
Other:			
Net foreign currency gains	16	4	24
Write off of contingent proceeds	(4)	—	(7)
Other	(15)	(11)	(21)
Total other	(3)	(7)	(4)
Net interest and other	$(274)	$(219)	$(107)

[a] Excludes $1 million and $10 million paid by United States Steel in 2012 and 2011 on assumed debt.

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

(In millions)	2013	2012	2011
Net interest and other	$16	$4	$24
Provision for income taxes	105	(80)	57
Aggregate foreign currency gains (losses)	$121	$(76)	$81

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10. Income Taxes
Income tax provisions (benefits) for continuing operations were:

	2013			2012			2011		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$63	$(46)	$17	$(80)	$(30)	$(110)	$(193)	$(217)	$(410)
State and local	44	1	45	(23)	47	24	24	82	106
Foreign	3,290	(15)	3,275	4,844	(241)	4,603	3,088	(58)	3,030
Total	$3,397	$(60)	$3,337	$4,741	$(224)	$4,517	$2,919	$(193)	$2,726

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

	2013	2012	2011
Statutory rate applied to income from continuing operations before income taxes	35 %	35 %	35 %
Effects of foreign operations, including foreign tax credits	14	18	6
Change in permanent reinvestment assertion	—	—	5
Adjustments to valuation allowances	18	21	14
Tax law changes	—	—	1
Other	1	—	—
Effective income tax rate on continuing operations	68 %	74 %	61 %

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income, the relative magnitude of these sources of income, and foreign currency remeasurement effects. The provision for income taxes is allocated on a discrete, stand-alone basis to pretax segment income and to individual items not allocated to segments. The difference between the total provision and the sum of the amounts allocated to segments appears in the "Not Allocated to Segments" column of the tables in Note 8.

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 in 2013 as a result of third-party labor strikes at the Es Sider oil terminal. The effects of foreign operations on our effective tax rate increased in 2012 from 2011, primarily due to the resumption of sales of Libyan production in 2012.

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 2013, 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.

Tax law changes – The U.K. enacted Finance Bill 2013 in July 2013 and Finance Bill 2012 in July 2012, which did not change the rate of corporation tax or the supplementary corporation tax for U.K. ring-fenced activities in the oil and gas sector. As such, this legislation did not have a material impact on our consolidated income tax provision. In July 2011, the U.K. enacted Finance Bill 2011 which increased the rate of the supplementary charge levied on profits from U.K. oil and gas production from 20 percent to 32 percent. As a result of this legislation, we recorded deferred tax expense of $10 million in 2011.

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

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Deferred tax assets and liabilities resulted from the following:

	December 31,	
(In millions)	2013	2012
Deferred tax assets:		
Employee benefits	$387	$510
Operating loss carryforwards	284	368
Foreign tax credits	5,730	4,351
Other	98	121
Valuation allowances:		
Federal	(2,997)	(2,067)
State, net of federal benefit	(67)	(60)
Foreign	(149)	(210)
Total deferred tax assets	3,286	3,013
Deferred tax liabilities:		
Property, plant and equipment	4,018	3,691
Investments in subsidiaries and affiliates	794	840
Other	67	12
Total deferred tax liabilities	4,879	4,543
Net deferred tax liabilities	$1,593	$1,530

Tax carryforwards – At December 31, 2013, our operating loss carryforwards included $744 million from Canada which expire in 2026 through 2030 and $128 million from the Kurdistan Region of Iraq that expire in 2016 through 2018. State operating loss carryforwards of $1,503 million expire in 2014 through 2033. Foreign tax credit carryforwards of $3,560 million expire in 2022 through 2023.

Valuation allowances – The estimated realizability of the benefit of foreign tax credits is based on certain estimates concerning future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and our tax profile in the years that such credits may be claimed. Federal valuation allowances increased $930 million, $1,277 million and $585 million in 2013, 2012 and 2011, 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.

Foreign valuation allowances decreased $61 million in 2013, primarily due the disposal of our Indonesian assets. Foreign valuation allowances increased $16 million and $52 million in 2012 and 2011, primarily due to deferred tax assets generated in the Kurdistan Region of Iraq, Angola and Indonesia.

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

	December 31,	
(In millions)	2013	2012
Assets:		
Other current assets	$53	$57
Other noncurrent assets	847	849
Liabilities:		
Other current liabilities	1	4
Noncurrent deferred tax liabilities	2,492	2,432
Net deferred tax liabilities	$1,593	$1,530

We are continuously undergoing examination of our U.S. federal income tax returns by the IRS. Such audits have been completed through the 2009 tax year. We believe adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities.

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As of December 31, 2013, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[a]	2004-2012
Canada	2008-2012
Equatorial Guinea	2007-2012
Libya	2006-2012
Norway	2008-2012
United Kingdom	2008-2012

[a] Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2013	2012	2011
Beginning balance	$98	$157	$103
Additions for tax positions related to the current year	14	—	4
Additions for tax positions of prior years	66	81	87
Reductions for tax positions of prior years	(25)	(67)	(29)
Settlements	(5)	(72)	(8)
Statute of limitations	(2)	(1)	—
Ending balance	$146	$98	$157

If the unrecognized tax benefits as of December 31, 2013 were recognized, $98 million would affect our effective income tax rate. There were $11 million of uncertain tax positions as of December 31, 2013 for which it is reasonably possible that the amount of unrecognized tax benefits would significantly increase or decrease during the next twelve months.

Interest and penalties are recorded as part of the tax provision and were $13 million, $4 million and $13 million related to unrecognized tax benefits in 2013, 2012 and 2011. As of December 31, 2013 and 2012, $15 million and $24 million of interest and penalties were accrued related to income taxes.

Pretax income from continuing operations included amounts attributable to foreign sources of $4,874 million, $6,382 million and $4,886 million in 2013, 2012 and 2011.

Undistributed income of certain consolidated foreign subsidiaries at December 31, 2013 amounted to $1,438 million for which no U.S. deferred income tax provision has been recorded because we intend to permanently reinvest such income in our foreign operations. If such income was not permanently reinvested, income tax expense of approximately $503 million would be recorded, not including potential utilization of foreign tax credits.

11. Inventories

Inventories are carried at the lower of cost or market value. The LIFO method accounted for 4 percent and 6 percent of total inventory value at December 31, 2013 and 2012. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2013 and 2012 by $32 million and $29 million.

	December 31,	
(In millions)	2013	2012
Liquid hydrocarbons, natural gas and bitumen	$55	$73
Supplies and other items	309	288
Inventories at cost	$364	$361

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12. Equity Method Investments and Related Party Transactions

During 2013, 2012 and 2011 only our equity method investees were considered related parties and they included:

- Alba Plant LLC, in which we have a 52 percent noncontrolling interest. Alba Plant LLC processes LPG.
- AMPCO, in which we have a 45 percent interest. AMPCO is engaged in methanol production activity.
- EGHoldings, in which we have a 60 percent noncontrolling interest. EGHoldings is engaged in LNG production activity.

Our equity method investments are summarized in the following table:

	Ownership as of	December 31,	
(In millions)	December 31, 2013	2013	2012
EGHoldings	60%	$748	$817
Alba Plant LLC	52%	263	264
AMPCO	45%	189	187
Other investments		1	11
Total		$1,201	$1,279

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $435 million in 2013, $381 million in 2012 and $509 million in 2011.

Summarized financial information for equity method investees is as follows:

(In millions)	2013	2012	2011
Income data – year:			
Revenues and other income	$1,444	$1,330	$1,544
Income from operations	849	755	942
Net income	727	635	820
Balance sheet data – December 31:			
Current assets	$644	$607	
Noncurrent assets	1,590	1,743	
Current liabilities	384	395	
Noncurrent liabilities	33	29	

Revenues from related parties were $55 million, $58 million and $60 million in 2013, 2012 and 2011, with the majority related to EGHoldings in all years. Purchases from related parties were $242 million, $248 million and $250 million in 2013, 2012 and 2011 with the majority related to Alba Plant LLC in all years.

Current receivables from related parties at December 31, 2013 and 2012, approximately split evenly between EGHoldings and AMPCO, were $30 million and $27 million. Payables to related parties were $20 million at December 31, 2013 and 2012, with the majority related to Alba Plant LLC.

13. Property, Plant and Equipment

	December 31,	
(In millions)	2013	2012
North America E&P	$26,755	$23,748
International E&P	12,428	13,214
Oil Sands Mining	10,436	10,127
Corporate	421	449
Total property, plant and equipment	50,040	47,538
Less accumulated depreciation, depletion and amortization	(21,895)	(19,266)
Net property, plant and equipment	$28,145	$28,272

During 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 in Libya 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 condition of our assets in Libya and uncertainty around production and sales levels remains. As of December 31, 2013, our net property, plant and equipment investment in Libya is approximately $761 million and total proved reserves (unaudited) in Libya are 249 mmboe.
Deferred exploratory well costs were as follows:

	December 31,		
(In millions)	2013	2012	2011
Amounts capitalized less than one year after completion of drilling	$512	$388	$482
Amounts capitalized greater than one year after completion of drilling	281	229	222
Total deferred exploratory well costs	$793	$617	$704
Number of projects with costs capitalized greater than one year after completion of drilling	7	6	5

	December 31,		
(In millions)	2013	2012	2011
Beginning balance	$617	$704	$657
Additions	746	699	625
Dry well expense	(147)	(111)	(223)
Transfers to development	(414)	(629)	(279)
Dispositions	(9)	(46)	(76)
Ending balance	$793	$617	$704

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2013 are summarized by geographical area below:

(In millions)	
Angola	$153
Norway	70
E.G.	22
Canada	36
Total	$281

Well costs that have been suspended for longer than one year are associated with seven projects. Management believes these projects with suspended exploratory drilling costs exhibit sufficient quantities of hydrocarbons to justify potential development.

Angola – Exploration on Angola Block 31 began in 2004, with costs accumulating through 2009. Exploration on Angola Block 32 began in 2011, with costs accumulating through 2013. In June and December 2013, we entered into agreements to sell our non-operated working interests in Angola Blocks 31 and 32 (see Note 6).

Norway – Three offshore Norway projects had costs incurred from 2009 through 2011. The development plan for Boyla was approved by the Norwegian government in October 2012. This will tie-back to the Alvheim FPSO and development drilling is planned in 2014, with first production expected in early 2015. Development options are being evaluated for the Caterpillar and Viper projects.

E.G. – The Corona well on Block D offshore E.G. was drilled in 2004, and we acquired an additional interest in the well in 2012. We plan to develop Block D through a unitization with the Alba field, which is currently being negotiated.

Canada – Exploration began on our Canadian in-situ assets at Birchwood in 2010 with costs accumulating through 2011. In 2012, we submitted a regulatory application for a proposed 12 mbbld 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.

14. Goodwill

Goodwill is tested for impairment on an annual basis, or when events or changes in circumstances indicate the fair value of a reporting unit with goodwill has been reduced below its carrying value. We performed our annual impairment tests during 2013, 2012 and 2011 and no impairment was required. The fair value of each of our reporting units with goodwill exceeded the book value appreciably.

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The changes in the carrying amount of goodwill for 2012 were as follows for the Exploration and Production ("E&P") and OSM segments in place for that year:

(In millions)	E&P	OSM	Total
2012			
Beginning balance, gross	$536	$1,412	$1,948
Less: accumulated impairments	—	(1,412)	(1,412)
Beginning balance, net	536	—	536
Dispositions	(11)	—	(11)
Ending balance, net	$525	$—	$525

As discussed in Note 8, beginning in 2013, we changed our reportable segments. Goodwill related to the previously reported E&P segment was allocated between the North America E&P and International E&P segments as of January 1, 2013 based on the relative fair values of those reporting units. The fair values of the reporting units were measured using an income approach based upon internal estimates of future production levels, commodity prices and discount rates, all of which are Level 3 inputs. Inputs to the fair value measurements included reserve and production estimates made by our reservoir engineers, estimated commodity prices adjusted for quality and location differentials, and forecasted operating expenses. The table below displays the allocated beginning goodwill balances by segment along with changes in the carrying amount of goodwill for 2013:

(In millions)	N.A. E&P	Int'l E&P	OSM	Total
2013				
Beginning balance, gross	$343	$182	$1,412	$1,937
Less: accumulated impairments	—	—	(1,412)	(1,412)
Beginning balance, net	343	182	—	525
Dispositions	4	(a) (30)	—	(26)
Ending balance, net	$347	$152	$—	$499

(a) Goodwill related to our Alaska disposition was less than the estimate classified as held for sale in 2012.

15. Fair Value Measurements

Fair values – Recurring

The following tables present assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2013 and 2012 by fair value hierarchy level.

	December 31, 2013				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Interest rate	$—	$8	$—	$—	$8
Foreign currency	—	2	—	—	2
Derivative instruments, assets	$—	$10	$—	$—	$10
Derivative instruments, liabilities					
Foreign currency	$—	$4	$—	$—	$4
Derivative instruments, liabilities	$—	$4	$—	$—	$4

	December 31, 2012				
(In millions)	Level 1	Level 2	Level 3	Collateral	Total
Derivative instruments, assets					
Commodity	$—	$52	$—	$1	$53
Interest rate	—	21	—	—	21
Foreign currency	—	18	—	—	18
Derivative instruments, assets	$—	$91	$—	$1	$92

Interest rate swaps are measured at fair value with a market approach using actionable broker quotes which are Level 2 inputs. Foreign currency forwards are measured at fair value with a market approach using third-party pricing services, such as

Bloomberg L.P., which have been corroborated with data from active markets for similar assets or liabilities, and are Level 2 inputs.

Commodity swaps in Level 2 are measured at fair value with a market approach using prices obtained from exchanges or pricing services, which have been corroborated with data from active markets for similar assets or liabilities. Commodity options in Level 2 are valued using the Black-Scholes Model. Inputs to this model include prices as noted above, discount factors, and implied market volatility. The inputs to this fair value measurement are categorized as Level 2 because predominantly all assumptions and inputs are observable in active markets throughout the term of the instruments. Collateral deposits related to commodity derivatives are in broker accounts covered by master netting agreements.

Fair values – Nonrecurring

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

	2013		2012		2011	
(In millions)	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$5	$96	$16	$371	$226	$285
Intangible assets	—	—	—	—	—	25

International E&P

Long-lived assets held for use – In light of E.G.'s recent natural gas policy developments related to the country's natural gas resources, we elected to cease our efforts to develop a second LNG production train on Bioko Island and recorded a $40 million impairment of all capitalized costs associated with engineering and feasibility studies in the fourth quarter of 2013. In addition, our share of income from EGHoldings included a $4 million impairment related to the same project which is reflected in income from equity method investments in the 2013 consolidated statement of income.

North America E&P

Long-lived assets held for use – The fair values were measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs. Inputs to the fair value measurement included reserve and production estimates made by our reservoir engineers, estimated commodity prices adjusted for quality and location differentials, and forecasted operating expenses for the remaining estimated life of the reservoir.

In the fourth quarter of 2012, declining natural gas prices related to our Powder River Basin asset prompted lower production expectations and reductions in estimated reserves which resulted in an impairment of $73 million. Subsequently, in the first quarter of 2013, as a result of our decision to wind down operations in the Powder River Basin due to poor economics, an additional impairment of $15 million was recorded to write down the asset's remaining fair value.

During early 2012, production rates from the Ozona development in the Gulf of Mexico declined significantly. Accordingly, our reserve engineers performed evaluations of our future production as well as our reserves and an impairment was recorded in the first quarter of 2012. As the development produced toward abandonment pressures, further downward revisions of reserves were taken for an aggregate impairment of $289 million in 2012. Ozona production ceased in the first quarter of 2013 and an additional $21 million impairment was recorded.

In May 2011, significant water production and reservoir pressure declines occurred at our Droshky development in the Gulf of Mexico. Plans for a waterflood were canceled and due to a decrease in proved reserves, a $273 million impairment of this asset to its $226 million fair value was recorded in 2011.

Other impairments of long-lived assets held for use in 2013, 2012 and 2011 were a result of reduced drilling expectations, reductions of estimated reserves or declining natural gas prices.

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

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Fair values – Financial instruments

Our current assets and liabilities include financial instruments, the most significant of which are receivables, commercial paper and payables. We believe the carrying values of our receivables, commercial paper and payables approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our investment-grade credit rating, and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The following table summarizes financial instruments, excluding receivables, commercial paper, payables and derivative financial instruments, and their reported fair value by individual balance sheet line item at December 31, 2013 and 2012.

	December 31,			
	2013		2012	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other noncurrent assets	$154	$147	$189	$186
Total financial assets	$154	$147	$189	$186
Financial liabilities				
Other current liabilities	$13	$13	$13	$13
Long-term debt, including current portion[a]	6,922	6,427	7,610	6,642
Deferred credits and other liabilities	149	147	94	94
Total financial liabilities	$7,084	$6,587	$7,717	$6,749

[a] Excludes capital leases.

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

Most of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions, which are Level 2 inputs, is used to measure the fair value of such debt. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

16. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 15. See Note 1 for discussion of the types of derivatives we use and the reasons for them. All of our interest rate and commodity derivatives are subject to enforceable master netting arrangements or similar agreements under which we may report net amounts. Netting is assessed by counterparty, and as of December 31, 2013 and 2012, there were no offsetting amounts. Positions by contract were all either assets or liabilities. The following tables present the gross fair values of derivative instruments, excluding cash collateral, and the reported net amounts along with where they appear on the consolidated balance sheets as of December 31, 2013 and 2012.

	December 31, 2013			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$8	$—	$8	Other noncurrent assets
Foreign currency	2	—	2	Other current assets
Total Designated Hedges	$10	$—	$10	

	December 31, 2013			
(In millions)	Asset	Liability	Net Liability	Balance Sheet Location
Fair Value Hedges				

Foreign currency	$—	$4	$4	Other current liabilities
Total Designated Hedges	$—	$4	$4	

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	December 31, 2012			
(In millions)	Asset	Liability	Net Asset	Balance Sheet Location
Fair Value Hedges				
Interest rate	$21	$—	$21	Other noncurrent assets
Foreign currency	18	—	18	Other current assets
Total Designated Hedges	39	—	39	
Not Designated as Hedges				
Commodity	52	—	52	Other current assets
Total Not Designated as Hedges	52	—	52	
Total	$91	$—	$91	

Derivatives Designated as Fair Value Hedges
The following table presents by maturity date, information about our interest rate swap agreements as of December 31, 2013, including the weighted average, London Interbank Offer Rate ("LIBOR")-based, floating rate.

Maturity Dates	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate
October 1, 2017	$600	4.65 %
March 15, 2018	$300	4.50 %

As of December 31, 2012, we had multiple interest rate swap agreements with a total notional amount of $600 million, a weighted average, LIBOR-based, floating rate of 4.70 percent and a maturity date of October 1, 2017.
In connection with debt retirements in February and March 2011, we settled interest rate swaps with a notional amount of $1,450 million. We recorded a $29 million gain, which reduced the loss on early extinguishment of debt.
As of December 31, 2013 and 2012, our foreign currency forwards had an aggregate notional amount of 2,387 million and 3,043 million Norwegian Kroner at weighted average forward rates of 6.060 and 5.780. These forwards hedge our current Norwegian tax liability and those outstanding at December 31, 2013 have settlement dates through June 2014.
The pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income are summarized in the table below. There is no ineffectiveness related to the fair value hedges.

		Gain (Loss)		
(In millions)	Income Statement Location	2013	2012	2011
Derivative				
Interest rate	Net interest and other	$(13)	$16	$28
Interest rate	Loss on early extinguishment of debt	—	—	29
Foreign currency	Provision for income taxes	(44)	(1)	—
Hedged Item				
Long-term debt	Net interest and other	$13	$(16)	$(28)
Long-term debt	Loss on early extinguishment of debt	—	—	(29)
Accrued taxes	Provision for income taxes	44	1	—

Derivatives Not Designated as Hedges
In August 2012, we entered into crude oil derivative instruments related to a portion of our forecasted North America E&P crude oil sales. These commodity derivatives were not designated as hedges and had terms that ended in December 2013.
The impact of all commodity derivative instruments not designated as hedges appears in sales and other operating revenues in our consolidated statements of income and were a net loss of $67 million in 2013 and net gains of $70 million and $5 million in 2012 and 2011.

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17. Debt
Short-term debt
As of December 31, 2013, we had no borrowings against our revolving credit facility, as described below, and we had $135 million in commercial paper outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.
Our $2.5 billion unsecured five-year revolving credit facility (the "Credit Facility") was entered in April 2012. The Credit Facility matures in April 2017, but allows us to request two one-year extensions. It contains an option to increase the commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, and includes sub-facilities for swing-line loans and letters of credit up to an aggregate amount of $100 million and $500 million, respectively. The agreement contains a covenant that requires our ratio of total debt to total capitalization not to exceed 65 percent as of the last day of each fiscal quarter. If an event of default occurs, the lenders may terminate the commitments under the Credit Facility and require the immediate repayment of all outstanding borrowings and the cash collateralization of all outstanding letters of credit under the Credit Facility.
Long-term debt
The following table details our long-term debt:

	December 31,	
(In millions)	2013	2012
Senior unsecured notes:		
9.125% notes due 2013	$—	$114
0.900% notes due 2015[(a)]	1,000	1,000
6.000% notes due 2017[(a)]	682	682
5.900% notes due 2018[(a)]	854	854
7.500% notes due 2019[(a)]	228	228
2.800% notes due 2022[(a)]	1,000	1,000
9.375% notes due 2022	32	32
Series A notes due 2022	3	3
8.500% notes due 2023	70	70
8.125% notes due 2023	131	131
6.800% notes due 2032[(a)]	550	550
6.600% notes due 2037	750	750
Capital leases:		
Capital lease obligation of consolidated subsidiary due 2014 – 2049	10	11
Other obligations:		
4.550% promissory note, semi-annual payments due 2014 – 2015	136	204
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Other	—	35
Total[(b)]	6,446	6,664
Unamortized discount	(9)	(11)
Fair value adjustments[(c)]	25	43
Amounts due within one year	(68)	(184)
Total long-term debt due after one year	$6,394	$6,512

(a) These notes contain a make-whole provision allowing us the right to repay the debt at a premium to market price.
(b) In the event of a change in control, as defined in the related agreements, debt obligations totaling $236 million at December 31, 2013, may be declared immediately due and payable.
(c) See Notes 15 and 16 for information on interest rate swaps.

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The following table shows five years of long-term debt payments:

(In millions)	
2014	$68
2015	1,068
2016	—
2017	682
2018	854

18. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)	2013	2012
Beginning balance	$1,783	$1,510
Incurred, including acquisitions	84	150
Settled, including dispositions	(78)	(35)
Accretion expense (included in depreciation, depletion and amortization)	106	91
Revisions to previous estimates	244	150
Held for sale	(43)	(83)
Ending balance[(a)]	$2,096	$1,783

(a) Includes asset retirement obligations of $87 million and $34 million classified as short-term at December 31, 2013 and 2012.

19. Supplemental Cash Flow Information

(In millions)	2013	2012	2011
Net cash provided by operating activities included:			
Interest paid (net of amounts capitalized)	$307	$225	$268
Income taxes paid to taxing authorities	3,904	4,974	2,893
Commercial paper:			
Issuances	$10,870	$13,880	$421
Repayments	(10,935)	(13,680)	(421)
Net commercial paper	$(65)	$200	$—
Noncash investing and financing activities, related to continuing operations:			
Additions to property, plant and equipment:			
Asset retirement costs capitalized, excluding acquisitions	$319	$257	$148
Change in capital expenditure accrual	(9)	187	104
Liabilities assumed in acquisitions	—	109	126
Asset retirement obligations assumed by buyer	92	8	5
Debt payments made by United States Steel	—	20	214

20. Defined Benefit Postretirement Plans and Defined Contribution Plan

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

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

Obligations and funded status – The accumulated benefit obligation for all defined benefit pension plans was $1,359 million and $1,442 million as of December 31, 2013 and 2012.

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As of December 31, 2013, our U.S. plans had accumulated benefit obligations in excess of plan assets, and as of December 31, 2012, our U.S. plans and our international ("Int'l") plans had accumulated benefit obligations in excess of plan assets. Summary information for these defined benefit pension plans follows.

	December 31,		
	2013	2012	
(In millions)	U.S.	U.S.	Int’l
Projected benefit obligation	$(933)	$(1,146)	$(565)
Accumulated benefit obligation	(791)	(937)	(505)
Fair value of plan assets	625	630	500

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

	Pension Benefits					
	2013		2012		Other Benefits	
(In millions)	U.S.	Int’l	U.S.	Int’l	2013	2012
Change in benefit obligations:						
Beginning balance	$1,146	$565	$986	$465	$311	$301
Service cost	33	22	31	19	4	4
Interest cost	40	24	42	22	12	14
Actuarial loss (gain)	(140)	40	196	49	(31)	8
Foreign currency exchange rate changes	—	11	—	25	—	—
Benefits paid	(146)	(13)	(109)	(15)	(17)	(16)
Ending balance	$933	$649	$1,146	$565	$279	$311
Change in fair value of plan assets:						
Beginning balance	$630	$500	$516	$412	$—	$—
Actual return on plan assets	65	74	66	57	—	—
Employer contributions	76	23	157	24	—	—
Foreign currency exchange rate changes	—	13	—	22	—	—
Benefits paid	(146)	(13)	(109)	(15)	—	—
Ending balance	$625	$597	$630	$500	$—	$—
Funded status of plans at December 31	$(308)	$(52)	$(516)	$(65)	$(279)	$(311)
Amounts recognized in the consolidated balance sheets:						
Current liabilities	(16)	—	(17)	—	(19)	(19)
Noncurrent liabilities	(292)	(52)	(499)	(65)	(260)	(292)
Accrued benefit cost	$(308)	$(52)	$(516)	$(65)	$(279)	$(311)
Pretax amounts in accumulated other comprehensive loss:						
Net loss (gain)	$262	$59	$511	$74	$(8)	$23
Prior service cost (credit)	15	9	21	10	(5)	(11)

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

	Pension Benefits								
	2013		2012		2011		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2013	2012	2011
Components of net periodic benefit cost:									
Service cost	$33	$22	$31	$19	$28	$19	$4	$4	$4
Interest cost	40	24	42	22	44	22	12	14	16
Expected return on plan assets	(43)	(24)	(43)	(22)	(43)	(23)	—	—	—
Amortization:									
- prior service cost (credit)	6	1	7	1	6	—	(6)	(7)	(7)
- actuarial loss	43	4	48	4	47	2	—	—	—
Net settlement loss[(a)]	45	—	45	—	30	—	—	—	—
Net periodic benefit cost[(b)]	$124	$27	$130	$24	$112	$20	$10	$11	$13
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)	$(161)	$(11)	$172	$15	$97	$24	$(31)	$7	$1
Amortization of actuarial (loss) gain	(88)	(4)	(93)	(4)	(77)	(2)	—	—	—
Prior service cost (credit)	—	—	—	1	—	(11)	—	—	—
Amortization of prior service credit (cost)	(6)	(1)	(7)	(1)	(6)	—	6	7	7
Spin-off downstream business [(c)]	—	—	—	—	(24)	—	—	—	—
Total recognized in other comprehensive (income) loss	$(255)	$(16)	$72	$11	$(10)	$11	$(25)	$14	$8
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$(131)	$11	$202	$35	$102	$31	$(15)	$25	$21

(a) Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. plans in 2013, 2012 and 2011.

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

(c) Includes net inter-company transfers of (gains)/losses due to the spin-off of the downstream business.

The estimated net loss and prior service cost for our defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2014 are $24 million and $6 million. The estimated prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2014 is $5 million.

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2013, 2012 and 2011.

	Pension Benefits								
	2013		2012		2011		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2013	2012	2011
Weighted average assumptions used to determine benefit obligation:									
Discount rate	4.28 %	4.60 %	3.44 %	4.40 %	4.45 %	4.70 %	4.85 %	4.06 %	4.90 %

Rate of compensation increase	5.00 %	4.90 %	5.00 %	4.50 %	5.00 %	4.30 %	5.00 %	5.00 %	5.00 %
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	3.79 %	4.40 %	4.21 %	4.70 %	5.05 %	5.40 %	4.06 %	4.90 %	5.55 %
Expected long-term return on plan assets	7.25 %[a]	4.90 %	7.75 %	5.20 %	8.50 %	5.86 %	—	—	—
Rate of compensation increase	5.00 %	4.50 %	5.00 %	4.30 %	5.00 %	5.10 %	5.00 %	5.00 %	5.00 %

(a) Effective January 1, 2014, the expected long-term return on U.S. plan assets was changed from 7.25 percent to 6.75 percent.

Expected long-term return on plan assets

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

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

Assumed health care cost trend rates

	2013	2012	2011
Health care cost trend rate assumed for the following year:			
Medical			
Pre-65	7.50%	8.00%	7.50%
Post-65	6.50%	7.00%	7.00%
Prescription drugs	7.00%	7.00%	7.50%
EGWP subsidy[a]	8.70%	7.50%	n/a
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate):			
Medical			
Pre-65	5.00%	5.00%	5.00%
Post-65	5.00%	5.00%	5.00%
Prescription drugs	5.00%	5.00%	5.00%
EGWP subsidy[a]	5.00%	5.00%	n/a
Year that the rate reaches the ultimate trend rate:			
Medical			
Pre-65	2020	2020	2018
Post-65	2020	2018	2017
Prescription drugs	2020	2018	2018
EGWP subsidy[a]	2020	2020	n/a

(a) An employee group waiver plan ("EGWP") is a group Medicare Part D prescription drug plan. Effective January 1, 2013, we implemented the EGWP as a result of the Patient Protection and Affordable Care Act, which ended tax-free status of retiree drug subsidy programs but increased federal funding to Part D prescription drug plans.

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

(In millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$2	$(2)
Effect on other postretirement benefit obligations	$30	$(25)

Plan investment policies and strategies – The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions.

Long-term investment goals are to: (1) manage the assets in accordance with the legal requirements of all applicable laws; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plans' investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation.

U.S. plan – Historical performance and future expectations suggest that common stocks will provide higher total investment returns than fixed income securities over a long-term investment horizon. Short-term investments are utilized for pension payments, expenses, and other liquidity needs. However, to reduce volatility in returns and to better match the plan's liabilities over time, as the plan’s funded ratio (as defined by the investment policy) improves, the allocation to equity securities will decrease while the amount allocated to fixed income securities will increase. As such, the plan’s current targeted asset allocation is comprised of 55 percent equity securities and high-yield bonds and 45 percent other fixed income securities.

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

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

Fair value measurements – Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2013 and 2012.

Cash and cash equivalents – Cash and cash equivalents include cash on deposit and an investment in a money market mutual fund that invests mainly in short-term instruments and cash, both of which are valued using a market approach and are considered Level 1. The money market mutual fund is valued at the net asset value ("NAV") of shares held. Cash and cash equivalents also include a cash reserve account (a collective short-term investment fund) that is valued using an income approach and is considered Level 2. The underlying assets are usually short-term bonds, discount notes, and commercial paper.

Equity securities – Investments in common stock, preferred stock, and real estate investment trusts ("REIT") are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. The non-public investment trust is valued using a market approach based on the underlying investments in the trust, which are publicly-traded securities, and is considered Level 2. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership, determined using a combination of market, income and cost approaches, plus working capital, adjusted for liabilities, currency translation and estimated performance incentives. These private equity investments are considered Level 3.

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

Pooled funds – Investments in pooled funds are valued using a market approach at the NAV of units held, but investment opportunities in such funds are limited to institutional investors on the behalf of defined benefit plans. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. The majority of the pooled funds are benchmarked against a relative public index. These are considered Level 2.

Fixed income securities – Fixed income securities are valued using a market approach. U.S. treasury notes and exchange traded funds are valued at the closing price reported in an active market, and are considered Level 1. Treasury inflation-protected securities ("TIPS") are valued at the daily closing price reported in an active market. TIPS prices exclude adjustment factors for inflation and are considered Level 1. Corporate bonds, non-U.S. government bonds, private placements, and yankee bonds are valued using calculated yield curves created by models that incorporate factors such as interest rate, benchmark quotes, trade data, dealer quotes, primary and secondary market spread activity, and other market information and are considered Level 2. Taxable municipal bonds are valued using calculated yield curves considering market factors such as benchmark issues, trades, trading spreads between similar issuers or creditors, historical trading spreads over widely accepted market benchmarks, and verified bid information. These assets are considered Level 2. Municipal bonds are valued by an evaluation of terms and conditions of the security and considering market factors such as benchmark curves, trades, bid price or spreads, two-sided markets, and quotes. These assets are considered Level 2. The investment in the commingled fund is valued using the NAV of units held, and is considered Level 2. The commingled fund consists mostly of high-yield U.S. and non-U.S. corporate bonds. Investment opportunities in this fund are limited to qualified retirement plans and their plan participants. The investment objective of the portfolio is to provide long-term total return in excess of the Barclays U.S. High Yield Bond Index.

Real estate – Real estate investments are valued using a combination of the income and market approaches that is based on discounted cash flows, comparable sales, outside appraisals, price per square foot or some combination thereof and therefore are considered Level 3.

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Other – Other investments are composed of an investment in an unallocated annuity contract, an investment contract with an international insurance carrier, and investments in two limited liability companies ("LLCs") with no public market. The LLCs were formed to acquire timberland in the northwest and other properties. The investment in an unallocated annuity contract is valued using a market approach based on the experience of the assets held in an insurer's general account. The majority of the general account is invested in a well-diversified portfolio of high-quality fixed income securities, primarily consisting of investment-grade bonds. Investment income is allocated among pension plans participating in the general account based on the investment year method. Under this method, a record of the book value of assets held is maintained in subdivisions according to the calendar year in which the funds are invested. The earnings rate for each of these calendar year subdivisions varies from year to year, reflecting the actual earnings on the assets attributed to that year. Due to the lack of transparency in the use of investment year subdivisions, this asset is considered Level 3. The insurance carrier contract is funded by premiums paid annually by the participating plans and the funds are invested by the insurance carrier in portfolios with different risk profiles (low, medium, high) that can be elected by clients. The majority of the underlying investments consists of a well-diversified mix of non-U.S. publicly traded equity securities valued at the closing price reported in an active market and fixed income securities valued using calculated yield curves. This asset is considered Level 2. The values of the LLCs are determined using a cost approach based on historical cost less depletion for timber previously harvested. These assets are considered Level 3.
The following tables present the fair values of our defined benefit pension plans' assets, by level within the fair value hierarchy, as of December 31, 2013 and 2012.

	December 31, 2013							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$19	$1	$1	$—	$—	$—	$20	$1
Equity securities:								
Common stock[(a)]	288	—	—	—	—	—	288	—
Preferred stock	4	—	—	—	—	—	4	—
Private equity	—	—	—	—	23	—	23	—
REIT	2	—	—	—	—	—	2	—
Mutual funds[(b)]	—	219	—	—	—	—	—	219
Pooled funds[(c)]	—	—	—	186	—	—	—	186
Fixed income securities:								
U.S. treasury notes	63	—	—	—	—	—	63	—
Exchange traded funds	1	—	—	—	—	—	1	—
Corporate bonds[(d)]	—	—	127	—	—	—	127	—
Municipal bonds	—	—	1	—	—	—	1	
Non-U.S. government bonds	—	—	7	—	—	—	7	—
Private placements	—	—	21	—	—	—	21	—
Taxable municipal bonds	—	—	13	—	—	—	13	—
Treasury inflation-protected securities	1	—	—	—	—	—	1	—
Yankee bonds	—	—	3	—	—	—	3	—
Commingled fund[(e)]	—	—	17	—	—	—	17	—
Pooled funds[(f)]	—	—	—	178	—	—	—	178
Real estate[(g)]	—	—	—	—	22	—	22	—
Other	—	—	—	13	12	—	12	13
Total investments, at fair value	$378	$220	$190	$377	$57	$—	$625	$597

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	December 31, 2012							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$16	$1	$1	$—	$—	$—	$17	$1
Equity securities:								
Common stock[(a)]	312	—	—	—	—	—	312	—
Private equity	—	—	—	—	25	—	25	—
REIT	2	—	—	—	—	—	2	—
Investment trust	—	—	1	—	—	—	1	—
Mutual funds[(b)]	—	171	—	—	—	—	—	171
Pooled funds[(c)]	—	—	—	152	—	—	—	152
Fixed income securities:								
U.S. treasury notes	67	—	—	—	—	—	67	—
Exchange traded funds	8	—	—	—	—	—	8	—
Corporate bonds[(d)]	—	—	96	—	—	—	96	—
Non-U.S. government bonds	—	—	5	—	—	—	5	—
Private placements	—	—	18	—	—	—	18	—
Taxable municipal bonds	—	—	14	—	—	—	14	—
Yankee bonds	—	—	2	—	—	—	2	—
Commingled fund[(e)]	—	—	28	—	—	—	28	—
Pooled funds[(f)]	—	—	—	166	—	—	—	166
Real estate[(g)]	—	—	—	—	23	—	23	—
Other	—	—	—	10	12	—	12	10
Total investments, at fair value	$405	$172	$165	$328	$60	$—	$630	$500

(a) Includes approximately 60 percent of investments held in U.S. and non-U.S. common stocks in the banking, pharmaceuticals, oil and gas, insurance, telecommunications, electric, aerospace/defense, retail, transportation, food processing, semiconductors, and chemicals sectors. The remaining 40 percent of common stock is held in various other sectors.

(b) Includes approximately 75 percent of investments held in U.S. and non-U.S. common stocks in the consumer staples, financial services, health care, energy, basic materials, leisure, and industrial goods and services sectors and 25 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, FTSE ALL Share 5% Capped Index and MSCI World Index, as defined by the investment policy.

(c) Includes approximately 80 percent of investments held in non-U.S. publicly traded common stocks (specifically Asia Pacific, except Japan, and the U.K.) in the financial, consumer staples, information technology, materials, energy, industrials, and telecommunication services sectors and the remaining 20 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, MSCI AC Asia Pacific ex Japan Index, FTSE Small Cap Index, and MSCI Emerging Markets Index, as defined by the investment policy.

(d) Includes approximately 70 percent of U.S. and non-U.S. corporate bonds in the banking and finance, utilities, oil and gas, news/media, and health care sectors. The remaining 30 percent of corporate bonds are in various other sectors.

(e) Includes approximately 90 percent of investments held in U.S. and non-U.S. corporate bonds in the consumer discretionary, financial, industrial, telecommunication services, energy, health care, information technology and materials sectors and 10 percent of investments held among various other sectors.

(f) Includes approximately 75 percent of investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds which include gilts, treasuries, financial, corporates, and collateralized asset backed securities and 25 percent of investments held among various other sectors. The funds' objective is to outperform their respective benchmark indexes, as defined by the investment policy.

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

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

	2013			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$25	$23	$12	$60
Actual return on plan assets:				
Realized gain	6	1	—	7
Unrealized gain (loss)	(1)	1	—	—
Purchases	6	1	—	7
Sales	(13)	(4)	—	(17)
Ending balance	$23	$22	$12	$57

	2012			
(In millions)	Private Equity	Real Estate	Other	Total
Beginning balance	$23	$21	$14	$58
Actual return on plan assets:				
Realized gain	2	—	—	2
Unrealized gain (loss)	1	1	(2)	—
Purchases	4	3	—	7
Sales	(5)	(2)	—	(7)
Ending balance	$25	$23	$12	$60

Cash flows

Estimated future benefit payments – The following gross benefit payments, which were estimated based on actuarial assumptions applied at December 31, 2013 and reflect expected future services, as appropriate, are to be paid in the years indicated.

	Pension Benefits		Other
(In millions)	U.S.	Int'l	Benefits
2014[(a)]	$96	$14	$19
2015	94	14	20
2016	95	16	20
2017	96	18	20
2018	92	21	20
2019 through 2023	368	120	98

(a) Primarily as a result of retirements effective January 1, 2014, actual 2014 U.S. gross benefit payments will exceed the actuarial estimate above, including approximately $163 million which will be paid during the first quarter of 2014.

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $77 million in 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.

Contributions to defined contribution plan – We contribute to a defined contribution plan for eligible employees. Contributions to this plan totaled $26 million, $25 million and $21 million in 2013, 2012 and 2011.

21. Incentive Based Compensation

Description of stock-based compensation plans – The Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan") was approved by our stockholders in April 2012 and authorizes the Compensation Committee of the Board of Directors to grant stock options, SARs, stock awards (including restricted stock and restricted stock unit awards) and performance awards to employees. The 2012 Plan also allows us to provide equity compensation to our non-employee directors. No more than 50 million shares of our common stock may be issued under the 2012 Plan. For stock options and SARs, the number of shares available for issuance under the 2012 Plan will be reduced by one share for each share of our common stock in respect of which the award is granted. For awards other than stock options or SARs, the number of shares available for issuance under the 2012 Plan will be reduced by 2.41 shares for each share of our common stock in respect of which the award is granted.

Shares subject to awards under the 2012 Plan that are forfeited, are terminated or expire unexercised become available for future grants. In addition, the number of shares of our common stock reserved for issuance under the 2012 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2012 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2012 Plan, no new grants were or will be made from the 2007 Incentive Compensation Plan, the 2003 Incentive Compensation Plan (the "2003 Plan"), the Non-Employee Director Stock Plan and the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors (collectively, the "Prior Plans"). Any awards previously granted under the Prior Plans shall continue to be exercisable in accordance with their original terms and conditions.

Stock-based awards under the plans

Stock options – We grant stock options under the 2012 Plan and previously granted stock options under certain of the Prior Plans. Our stock options represent the right to purchase shares of our common stock at its fair market value on the date of grant. In general, our stock options vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Stock appreciation rights – Prior to 2005, we granted SARs under the 2003 Plan. No SARs have been granted since then. SARs represent the right to receive shares of common stock equal in value to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. In general, SARs vested ratably over a three-year period and have a maximum term of ten years from the date they were granted.

Restricted stock – We grant restricted stock and restricted stock units (collectively, "restricted stock awards") under the 2012 Plan and previously granted such awards under certain of the Prior Plans. The restricted stock awards granted officers generally vest three years from the date of grant, contingent on the recipient’s continued employment. We also grant restricted stock to certain non-officer employees and restricted stock units to certain international employees, based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest in one-third increments over a three-year period, contingent on the recipient’s continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by our transfer agent.

Stock-based performance units – Beginning in 2013, we grant stock-based performance units to officers under the 2012 Plan. At the grant date, each unit represents the value of one share of our common stock. These units provide a cash payout, based on the value of anywhere from zero to two times the number of units granted, upon the achievement of certain performance goals at the end of a 36-month performance period. The performance goals are tied to our total shareholder return (“TSR”) as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. Dividend equivalents accrue during the performance period and are paid in cash at the end of the performance period based on the number of shares that would represent the value of the units.

Common stock units – We maintain an equity compensation program for our non-employee directors under the 2012 Plan and previously maintained such a program under certain of the Prior Plans. All non-employee directors receive annual grants of common stock units. Those units granted prior to 2012 must be held until completion of board service, at which time the non-employee director will receive common shares. Common shares will be issued for units granted on or after January 1, 2012 upon completion of board service or three years from the date of grant, whichever is earlier. When dividends are paid on our common stock, directors receive dividend equivalents in the form of additional common stock units.

Total stock-based compensation expense – Total employee stock-based compensation expense was $75 million, $70 million and $65 million in 2013, 2012 and 2011, while the total related income tax benefits were $27 million, $25 million and $23 million in the same years. In 2013, 2012 and 2011, cash received upon exercise of stock option awards was $58 million, $41 million and $77 million. Tax benefits realized for deductions for stock awards exercised during 2013, 2012 and 2011 totaled $36 million, $24 million and $32 million.

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Stock option awards – During 2013, 2012 and 2011, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following weighted average Black-Scholes assumptions:

	2013		2012		2011	
Exercise price per share	$33.54		$33.52		$32.30	
Expected annual dividend yield	2.1	%	2.2	%	2.1	%
Expected life in years	6.1		5.5		5.3	
Expected volatility	38	%	41	%	40	%
Risk-free interest rate	1.6	%	1.2	%	1.7	%
Weighted average grant date fair value of stock option awards granted	$10.25		$10.86		$10.44	

The following is a summary of stock option award activity in 2013.

	Number of Shares	Weighted Average Exercise price
Outstanding at beginning of year	19,536,965	$26.19
Granted	2,051,386	$33.54
Exercised	(2,718,639)	$22.36
Canceled	(764,825)	$34.02
Outstanding at end of year	18,104,887	$27.27

The intrinsic value of stock option awards exercised during 2013, 2012 and 2011, was $35 million, $40 million and $59 million.

The following table presents information related to stock option awards at December 31, 2013.

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Shares Under Option	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Under Option	Weighted Average Exercise Price
$7.99-12.75	259,164	0.3 years	$10.53	259,164	$10.53
$12.76-16.81	1,937,181	3 years	$15.13	1,937,181	$15.13
$16.82-23.20	4,255,365	5 years	$18.57	4,255,365	$18.57
$23.21-29.24	1,740,398	4 years	$24.59	1,489,683	$24.05
$29.25-36.03	7,541,433	7 years	$33.06	3,967,422	$32.70
$36.04-46.41	2,371,346	3 years	$38.19	2,277,817	$38.26
Total	18,104,887	5 years	$27.27	14,186,632	$25.64

As of December 31, 2013, the aggregate intrinsic value of stock option awards outstanding was $152 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable were $144 million and 4 years.

As of December 31, 2013, the number of fully-vested stock option awards and stock option awards expected to vest was 18,023,888. The weighted average exercise price and weighted average remaining contractual life of these stock option awards were $27.24 and 5 years and the aggregate intrinsic value was $152 million. As of December 31, 2013, unrecognized compensation cost related to stock option awards was $16 million, which is expected to be recognized over a weighted average period of 2 years.

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Restricted stock awards – The following is a summary of restricted stock award activity in 2013.

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	4,177,884	$29.02
Granted	2,120,839	$33.69
Vested	(1,713,763)	$27.78
Forfeited	(553,072)	$30.58
Unvested at end of year	4,031,888	$31.80

The vesting date fair value of restricted stock awards which vested during 2013, 2012 and 2011 was $59 million, $36 million and $30 million. The weighted average grant date fair value of restricted stock awards was $31.80, $29.02, and $25.88 for awards unvested at December 31, 2013, 2012 and 2011.

As of December 31, 2013, there was $96 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of 2 years.

Stock-based performance unit awards – During 2013, we granted 353,600 stock-based performance unit awards to officers and at December 31, 2013, there were 93,100 units outstanding. The key assumptions used in the Monte Carlo simulation to determine the December 31, 2013 fair value of stock-based performance units were:

Valuation date stock price	$35.30	
Expected annual dividend yield	2.1	%
Expected volatility	26	%
2-Year risk-free interest rate	0.4	%
Fair value of stock-based performance units outstanding	$34.08	

Cash-based performance unit awards – Prior to 2013, cash-based performance unit awards were granted to officers that provide a cash payment upon the achievement of certain performance goals at the end of a defined measurement period. The performance goals are tied to our TSR as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. The target value of each performance unit is $1, with a maximum payout of $2 per unit, but the actual payout could be anywhere between zero and the maximum. Because performance units are to be settled in cash at the end of the performance period, they are accounted for as liability awards.

During 2012, we granted 12.7 million performance units, all having a 36-month performance period. During the third quarter of 2011, we granted 15 million performance units, a portion of which had a 30-month performance period and a portion of which had an 18-month performance period to reflect the remaining periods of the original 2011 and 2010 performance unit grants outstanding prior to the spin-off. Compensation expense associated with cash-based performance units was $9 million, $12 million and $32 million in 2013, 2012 and 2011. The expense for 2011 included $14 million paid on three groups of performance unit grants outstanding at June 30, 2011, that were accelerated with the total payout determined based on performance through the effective date of the spin-off of our downstream business.

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22. Reclassifications Out of Accumulated Other Comprehensive Loss

The following table presents a summary of amounts reclassified from accumulated other comprehensive loss to net income in their entirety:

(In millions)	2013	Income Statement Line
Accumulated Other Comprehensive Loss Components		
	Income (Expense)	
Postretirement and postemployment plans		
Amortization of actuarial loss	$(47)	General and administrative
Net settlement loss	(45)	General and administrative
	35	Provision for income taxes
	(57)	Net of tax
Other insignificant items, net of tax	(1)	
Total reclassifications for the period	$(58)	Net income

23. Stockholders' Equity

Share repurchase plan – In the third quarter of 2013, we acquired 14 million common shares at a cost of $500 million under our share repurchase program, initially authorized in 2006, bringing our total repurchases to 92 million common shares at a cost of $3,722 million. In December 2013, our Board of Directors increased the authorization by an additional $1.2 billion, bringing the total remaining share repurchase authorization to $2.5 billion. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables.

24. Leases

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

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2014	$1	$45
2015	1	42
2016	1	34
2017	1	22
2018	1	20
Later years	23	48
Sublease rentals	—	(4)
Total minimum lease payments	$28	$207
Less imputed interest costs	(18)	
Present value of net minimum lease payments	$10	

Operating lease rental expense related to continuing operations was $106 million, $103 million and $70 million in 2013, 2012 and 2011.

25. Commitments and Contingencies

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

Litigation – In March 2011, Noble Drilling (U.S.) LLC (“Noble”) filed a lawsuit against us in the District Court of Harris County, Texas, alleging, among other things, breach of contract, breach of the duty of good faith and fair dealing, and negligent misrepresentation, relating to a multi-year drilling contract for a newly constructed drilling rig to be deployed in the U.S. Gulf of Mexico. We filed an answer in April 2011, contending, among other things, failure to perform, failure to comply with material obligations, failure to mitigate alleged damages and that Noble failed to provide the rig according to the operating, performance and safety requirements specified in the drilling contract. 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 matters – We are subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

At December 31, 2013 and 2012, accrued liabilities for remediation were not significant. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed.

Guarantees – We have entered into a guarantee of a long-term transportation services agreement and a performance guarantee related to asset retirement obligations with aggregate maximum potential undiscounted payments totaling $96 million as of December 31, 2013. Under the terms of these guarantee arrangements, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements.

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

Contract commitments – At December 31, 2013 and 2012, contractual commitments to acquire property, plant and equipment totaled $1,270 million and $949 million.

Other contingencies – During the second quarter of 2011, the AOSP operator determined the need and developed preliminary plans to address water flow into a previously mined and contained section of the Muskeg River mine. Our share of the estimated costs in the amount of $64 million was recorded to production expense in 2011. At December 31, 2013, the remaining liability is $29 million.

Select Quarterly Financial Data (Unaudited)

	2013				2012			
(In millions, except per share data)	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
Revenues	$3,784	$3,839	$3,699	$3,179	$3,793	$3,732	$4,036	$4,131
Income from continuing operations before income taxes	1,367	1,467	1,278	818	1,350	1,421	1,733	1,626
Income from continuing operations	380	399	518	296	423	406	469	315
Discontinued operations [(a)]	3	27	51	79	(6)	(13)	(19)	7
Net income	$383	$426	$569	$375	$417	$393	$450	$322
Income per share:								
Basic:								
Continuing operations	$0.54	$0.56	$0.73	$0.43	$0.60	$0.58	$0.67	$0.45
Discontinued operations [(a)]	$0.00	$0.04	$0.07	$0.11	($0.01)	($0.02)	($0.03)	$0.01
Net income	$0.54	$0.60	$0.80	$0.54	$0.59	$0.56	$0.64	$0.46
Diluted:								
Continuing operations	$0.54	$0.56	$0.73	$0.43	$0.60	$0.58	$0.66	$0.44
Discontinued operations [(a)]	$0.00	$0.04	$0.07	$0.11	($0.01)	($0.02)	($0.03)	$0.01
Net income	$0.54	$0.60	$0.80	$0.54	$0.59	$0.56	$0.63	$0.45
Dividends paid per share	$0.17	$0.17	$0.19	$0.19	$0.17	$0.17	$0.17	$0.17

[(a)] In 2013, we entered into agreements to sell our Angola assets; therefore, our Angola operations are reflected as discontinued operations in all periods presented.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the U.S.; Canada; E. G.; Other Africa, which primarily includes activities in Gabon, Kenya, Ethiopia and Libya; Europe, which primarily includes activities in Norway and the U.K.; and Other International ("Other Int'l"), which includes activities in the Kurdistan Region of Iraq. Our Angola operations are shown as discontinued operations ("Disc Ops") in all periods since we entered into agreements to sell these assets in 2013.

Estimated Quantities of Proved Oil and Gas Reserves

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

(mmbbl)	U.S.	Canada	E.G.[(a)]	Other Africa	Europe	Disc Ops	Total
Liquid Hydrocarbons							
Proved developed and undeveloped reserves:							
Beginning of year - 2011	173	—	119	224	99	15	630
Revisions of previous estimates	16	—	11	—	21	2	50
Improved recovery	1	—	—	—	—	—	1
Purchases of reserves in place	89	—	—	—	—	—	89
Extensions, discoveries and other additions	27	—	—	—	14	1	42
Production	(27)	—	(13)	(2)	(37)	—	(79)
End of year - 2011	279	—	117	222	97	18	733
Revisions of previous estimates	9	—	6	(5)	28	—	38
Improved recovery	2	—	—	—	—	—	2
Purchases of reserves in place	52	—	—	—	—	—	52
Extensions, discoveries and other additions	172	—	—	7	—	—	179
Production	(39)	—	(13)	(15)	(36)	—	(103)
End of year - 2012	475	—	110	209	89	18	901
Revisions of previous estimates	46	—	(1)	12	26	(1)	82
Improved recovery	—	—	—	—	—	11	11
Purchases of reserves in place	14	—	—	—	—	—	14
Extensions, discoveries and other additions	137	—	1	3	5	3	149
Production	(55)	—	(12)	(9)	(31)	(3)	(110)
Sales of reserves in place	(1)	—	—	—	—	—	(1)
End of year - 2013	616	—	98	215	89	28	1,046
Proved developed reserves:							
Beginning of year - 2011	124	—	86	180	89	—	479
End of year - 2011	141	—	78	179	84	—	482
End of year - 2012	198	—	68	168	84	—	518
End of year - 2013	292	—	55	176	78	19	620
Proved undeveloped reserves:							
Beginning of year - 2011	49	—	33	44	10	15	151
End of year - 2011	138	—	39	43	13	18	251
End of year - 2012	277	—	42	41	5	18	383
End of year - 2013	324	—	43	39	11	9	426

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(bcf)	U.S.	Canada	E.G.[a]	Other Africa	Europe	Disc Ops	Total
Natural Gas							
Proved developed and undeveloped reserves:							
Beginning of year - 2011	745	—	1,651	105	116	—	2,617
Revisions of previous estimates	18	—	81	(1)	22	—	120
Purchases of reserves in place	119	—	—	—	—	—	119
Extensions, discoveries and other additions	109	—	—	—	11	—	120
Production[b]	(119)	—	(161)	—	(30)	—	(310)
End of year - 2011	872	—	1,571	104	119	—	2,666
Revisions of previous estimates	(29)	—	10	(1)	15	—	(5)
Purchases of reserves in place	105	—	—	—	—	—	105
Extensions, discoveries and other additions	224	—	—	111	—	—	335
Production[b]	(129)	—	(157)	(5)	(31)	—	(322)
End of year - 2012	1,043	—	1,424	209	103	—	2,779
Revisions of previous estimates							