Marathon Oil Corporation

Dear Fellow Stockholders,

We are pleased to report that Marathon Oil successfully delivered against our performance commitments during 2014, which included significantly growing production in our highest-value U.S. unconventional resource plays, completing key strategic divestitures in Angola and Norway, and providing shareholder value through an increased dividend and $1 billion in share repurchases. We achieved these results while remaining grounded in our core values and exercising discipline across our seven strategic imperatives.

In our three core U.S. resource basins, Marathon Oil achieved 35 percent yearly production growth and grew our 2P* resource base to 3 billion barrels of oil equivalent (boe), a 20 percent increase over year-end 2013. Asset sales of more than $4 billion reshaped and concentrated our portfolio to higher margin, higher return organic growth opportunities. Even in the lower commodity price environment, our U.S. resource plays generate competitive returns that are indicative of their subsurface quality and our ability to execute efficiently at scale. We are not opportunity limited.

Marathon Oil is well prepared for the current lower oil price environment and our focus is on generating the highest returns, protecting our balance sheet and positioning for price recovery. We are concentrating on those elements of our business that we control to expand our margins, including capital efficiency, investment high grading, expense management, service cost reductions, operational reliability and aligning organizational capacity with lower activity levels. We have a deep, multi-year resource play drilling inventory that is robust across a broad range of pricing scenarios and have captured material reductions in service costs early in the cycle that enhance our already strong single well economics. Our $3.5 billion capital budget for 2015 is expected to generate a total Company production growth rate, excluding Libya, of 5 to 7 percent year over year. Importantly, our focus on delivering value in any price environment and protecting our financial flexibility has us positioned to be a stronger exploration and production (E&P) company in the long term.

Operating and capital efficiency provide competitive advantage

Outstanding 97 percent average availability in our operated assets supported improved margins and returns and reflects the commitment of our asset teams to deliver our most economic barrels. We leveraged the scale and efficiencies in our unconventional resource plays, with fourth quarter average time from spud-to-total depth of 12 days in Eagle Ford and 16 days in the Bakken. We also continued to pilot and adopt advanced completion technologies and downspacing to improve recoveries and expand forward inventory.

High-return resource plays deliver 35 percent growth

Total Company production available for sale from continuing operations, excluding Libya, increased 8 percent to an average of 399,000 net boe per day (boed) in 2014, compared to an average of 371,000 net boed in 2013. This increase was driven primarily by year-over-year net production growth in the Eagle Ford, Bakken and Oklahoma Resource Basins of 38 percent, 31 percent and 29 percent, respectively.

Focusing capital on our three core U.S. resource plays resulted in a 2014 proved reserve replacement rate of 183 percent, excluding dispositions, at a competitive finding and development cost of approximately $20 per boe. Driven primarily by U.S. resource play activity, we added net proved reserves of 305 million boe that now stand at 80 percent liquids and 67 percent developed. For the three-year period ended Dec. 31, 2014, Marathon Oil added just over 1 billion boe in net proved reserves, excluding dispositions, resulting in a three-year average reserve replacement ratio of just over 200 percent.

With predictable execution delivering returns and consistent growth, our U.S. resource plays accounted for more than half of Marathon Oil's E&P production in the second half of 2014. Eagle Ford production in the fourth quarter averaged 131,000 net boed, 46 percent higher than the fourth quarter of 2013. Fourth quarter Bakken production averaged 55,000 net boed, up 38 percent year over year. In the Oklahoma Resource Basins, fourth quarter production averaged 20,000 net boed, up 43 percent from the prior year quarter.

Rigorous portfolio management contributes $4 billion in proceeds from asset sales

Our commitment to ongoing portfolio management further reshaped our asset base in 2014, concentrating our business to higher margin, higher return opportunities while contributing liquidity to our balance sheet and enabling the repurchase of $1 billion in shares.

**2P defined on back cover.*

Scalable capital program supports profitable investments, production growth
Marathon Oil deployed our $5.9 billion capital and exploration budget to generate profitable production growth in 2014. Our 2015 budget of $3.5 billion directs 70 percent of spending to high-return investment opportunities in our three U.S. resource plays and reduces exploration spending by more than 50 percent. Though not opportunity limited at current pricing, we are protecting our flexibility in this uncertain environment by reducing activity and rig count in the resource plays from 33 at year-end 2014 to 14 by the end of the second quarter of 2015. Based on this level of activity, we anticipate 2015 total Company production growth of approximately 5 to 7 percent, excluding Libya, with production growth in our three key U.S. resource plays of approximately 20 percent. We retain the ability to exercise further flexibility in spending as the pricing and the macro environment warrant.

A further breakdown of our 2015 investment plans shows that over $1.4 billion, or about 40 percent of spending, is allocated to the Eagle Ford, where we have compelling single well economics and best-in-class execution at scale. We have budgeted $760 million for the Bakken, targeting the highest quality Myrmidon wells. Our $226 million capital budget in the Oklahoma Resource Basins focuses on continued delineation and exploration while protecting our valuable leasehold. In our international business, we plan to spend $429 million, primarily in Equatorial Guinea, the United Kingdom and the Kurdistan Region of Iraq. Our 2015 budget includes $232 million supporting a targeted exploration program that includes one operated well and one non-operated appraisal well in the Gulf of Mexico, as well as seismic surveys in Gabon and Ethiopia.

Delivering long-term shareholder value
Marathon Oil increased our dividend 11 percent in 2014 and completed $1 billion in share repurchases. It is also important to highlight our Company's financial strength, which includes year-end 2014 liquidity of $4.9 billion consisting of $2.4 billion in cash and $2.5 billion available through a committed multi-year credit facility. This enhances Marathon Oil's ability to execute our business plans across a range of commodity price scenarios.

Additionally, we were pleased to welcome energy sector leader Marcela E. Donadio to our board of directors, and we look forward to the contributions her strong background in accounting and financial management will bring to our Company. We also offer our thanks to Dr. Shirley Jackson for her many years of service on our board of directors.

To all of our employees, thank you for your continued commitment to Marathon Oil's success. Your dedication to making our Company the premier independent E&P enabled us to realize many achievements in 2014 and to position us for the future. And to our stockholders, thank you for the confidence you have placed in our entire organization and the leadership team to be responsible stewards of your investment in our Company.

As we move forward in this dynamic business environment, we remain steadfast in our commitment to create long-term shareholder value. The cyclical nature of our industry will not prevent Marathon Oil from striving to be the employer, operator, business partner and investment of choice among independent E&P companies.

Respectfully,

Lee M. Tillman
President and Chief Executive Officer

Dennis H. Reilley
Chairman of the Board of Directors

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, 2014

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of Common Stock held by non-affiliates as of June 30, 2014: $26,831 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 674,944,619 shares of Marathon Oil Corporation Common Stock outstanding as of February 23, 2015.

Documents Incorporated By Reference:
Portions of the registrant's proxy statement relating to its 2015 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

MARATHON OIL CORPORATION

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

Table of Contents

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 non-operated working 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.

btu – British thermal unit, an energy equivalence measure.

Budget – Our capital, investment and exploration spending budget as made public through a press release.

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 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.

EIA – United States Energy Information Agency.

EPA – United States Environmental Protection Agency.

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 crude oil and condensate, NGLs 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.

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.

LNG – Liquefied natural gas.

LPG – Liquefied petroleum gas.

Liquid hydrocarbons or liquids – Collectively, crude oil, synthetic crude oil, condensate and natural gas liquids.

LLS – Louisiana Light Sweet crude oil, an oil index benchmark price.

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

Marathon Oil – Marathon Oil Corporation and its consolidated subsidiaries: 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 – Our North America Exploration and Production segment *("N.A. E&P")* which explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America.

OCI – Other comprehensive income.

OECD – Organization for Economic Cooperation and Development.

OPEC – Organization of Petroleum Exporting Countries.

Operational availability – A term used to measure the ability of an asset to produce to its maximum capacity over a specified period of time, after consideration of Internal Losses.

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

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

Proved 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 and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved reserves – Proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves are those quantities of crude oil and condensate, NGLs, natural gas and synthetic crude oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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 or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

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 and natural gas produced.

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

SAGE – 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).

STACK – Sooner Trend, Anadarko (basin), Canadian (and) Kingfisher (counties).

Total depth ("TD") – The bottom of a drilled hole.

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, including 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, contains 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 (the "Exchange Act"). All statements other than statements of historical fact included or incorporated by reference in this report are forward-looking statements, including without limitation statements regarding: our operational, financial and growth strategies, ability to successfully effect those strategies and the expected results therefrom; our 2015 capital, investment and exploration budget and the planned allocation thereof; planned capital expenditures and the impact thereof; planned activities, including drilling plans and projects, planned wells, rig count, inventory, seismic, exploration plans and maintenance activities, and the expected timing and impact thereof; expectations regarding future economic and market conditions and the effects on us thereof; our financial and operational outlook, and ability to fulfill that outlook; our financial position, balance sheet, liquidity and capital resources, and the benefits thereof; resource and asset quality and the expected benefits and performance thereof; reserve estimates and growth expectations; future production and sales expectations, and the drivers thereof; and statements related to enhanced completion designs, downspacing, co-development, high-density pilots, and the expected benefits and results thereof. In addition, many forward-looking statements may be identified by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "targets," "plans," "projects," "could," "may," "should," "would" or similar words indicating that future outcomes are uncertain. While we believe that our assumptions concerning future events are reasonable, we can give no assurance that these expectations will prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to:

- conditions in the oil and gas industry, including the level of supply or demand for crude oil and condensate, NGLs, natural gas and synthetic crude oil and the impact on the price of crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- changes in political or economic conditions in key operating markets, including international markets;
- the amount of capital available for exploration and development;
- 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;
- non-performance by third parties of their contractual obligations;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto;
- cyber-attacks adversely affecting our operations;
- changes in safety, health, environmental and other regulations;
- other geological, operating and economic considerations; and
- other factors discussed in Item 1. Business, Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and elsewhere in this report.

All forward-looking statements included in this report are based on information available to us on the date of this report. Except as required by law, we assume no duty to revise or update any forward-looking statements whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

PART I

Item 1. Business

General

Marathon Oil Corporation is a global energy company based in Houston, Texas, with operations in North America, Europe and Africa. Our corporate headquarters are located at 5555 San Felipe Street, Houston, Texas 77056-2723 and our telephone number is (713) 629-6600. Each of our three reportable operating segments is organized based upon both geographic location and the nature of the products and services it offers.

- North America E&P – explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America;
- International E&P – explores for, produces and markets crude oil and condensate, NGLs 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.

We were incorporated in 2001. On June 30, 2011, we completed the spin-off of our downstream business, creating two independent energy companies: Marathon Oil and MPC.

Strategy and Results Summary

We have production operations in the U.S., E.G., Canada, the U.K. and Libya. The focus of our U.S. operations is our three core unconventional resource plays: the Eagle Ford, Bakken and Oklahoma Resource Basins. Our exploration prospects are in E.G., Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq and the U.S, primarily in the Gulf of Mexico. Our strategy is guided by the following seven strategic imperatives ("SI^7"):

1. Living Our Values
2. Investing in Our People
3. Continuous Improvement in Operational and Capital Efficiency
4. Driving Profitable and Sustainable Growth
5. Rigorous Portfolio Management
6. Quality and Material Resource Capture
7. Delivering Long-Term Shareholder Value

In 2014, we continued to focus on liquid hydrocarbon reserves, realizing substantial increases in our three unconventional resource plays, the Eagle Ford, Bakken and Oklahoma Resource Basins. In 2014, our U.S. operations added 288 mmboe proved reserves, excluding acquisitions, dispositions and production, amounting to an increase of 37 percent over the prior year's ending balance.

For the total company, we ended 2014 with proved reserves of approximately 2,198 mmboe, compared to 2,171 mmboe at the end of 2013. Excluding proved reserves of 106 mmboe related to our Angola and Norway discontinued operations, proved reserves related to continuing operations increased from 2,065 mmboe at the end of 2013 to 2,198 mmboe at the end of 2014 for an increase of 6 percent.

We continually evaluate ways to optimize our portfolio through acquisitions and divestitures. In 2014, we executed two strategic dispositions for aggregate cash proceeds of more than $4 billion. We closed the sale of our Angola assets in the first quarter and our Norway business in the fourth quarter.

During 2014, we repurchased approximately 29 million shares for $1 billion. Our cash additions to property, plant and equipment related to continuing operations were $5.2 billion, primarily funded with cash flow from operations, with more than 70 percent of that related to our Eagle Ford, Bakken and Oklahoma Resource Basins where net sales volumes increased 35 percent year-over-year.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Outlook, for discussion of our 2015 Budget.

The map below shows 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 7 to the consolidated financial statements.

In the following discussion 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, 2014, we had approximately 180,000 net acres in the Eagle Ford in south Texas and 954 gross (714 net) operated producing wells, where we have been operating since 2011. During 2014, we reached total depth on 360 gross operated wells and brought 310 gross operated wells to sales, compared to 299 reaching total depth and 307 brought to sales in 2013. Included with the Eagle Ford well counts noted above, were 22 gross operated Austin Chalk wells brought online in 2014 and the first four Upper Eagle Ford wells which were brought online late in the fourth quarter of 2014. Our 2014 average spud-to-TD time was 13 days compared to 12 days in 2013. Our high-density pad drilling continues to average approximately four wells per pad in 2014. This higher pad density and the longer laterals being drilled in 2014 contribute to the slightly higher spud-to-TD time in 2014.

Throughout 2013, we evaluated the potential of downspacing to 40-acre and 60-acre spacing with several pilot programs. Wells drilled in these programs at closer spacing showed improved completion efficiency which helped offset impacts due to tighter well spacing. The continued focus on stimulation design has contributed to incremental improvements in well performance across our area of activity.

Eagle Ford net sales in 2014 were 112 mboed, 65 percent crude oil and condensate, 17 percent NGLs and 18 percent natural gas, compared to 81 mboed in 2013, a 38 percent increase. In 2014, we transported approximately 70 percent of our

Eagle Ford production by pipeline and anticipate this to increase to 90 percent in 2015 as additional pipeline capacity is constructed and completed. The ability to transport more barrels by pipeline enables us to improve/optimize price realizations, reduce costs, improve reliability and lessen our environmental footprint.

During 2014, we continued evaluation of the Austin Chalk formation across our Eagle Ford acreage position in south Texas, delineating 18,000 initial Austin Chalk acres and bringing online 22 wells. Initial Austin Chalk production results indicate that the mix of crude oil and condensate, NGLs and natural gas is similar to Eagle Ford condensate wells. We plan to drill 56 to 62 additional gross wells in the Austin Chalk formation in 2015. Co-development of the Austin Chalk and Lower Eagle Ford will leverage the infrastructure investments we have made to support production growth across the Eagle Ford operating area. During the fourth quarter of 2014, the first four Upper Eagle Ford wells were brought online and we spud our first four-well pilot with Austin Chalk, Upper Eagle Ford, and two Lower Eagle Ford wells.

We operate approximately 800 miles of gathering pipeline in the Eagle Ford area. We now have 31 central gathering and treating facilities, with aggregate capacity of more than 460 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.

Approximately 40 percent of our 2015 Budget, $1.4 billion, is allocated to the Eagle Ford. Our drilling plans for 2015 include drilling 141 - 152 net wells (245 - 260 gross, of which we will operate 215 - 225), a decrease of approximately 40 percent over 2014. We anticipate bringing 255 - 275 gross operated wells to sales during 2015.

Bakken – We hold approximately 290,000 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. We began high-density spacing pilots in 2014, with each pad comprised of six Middle Bakken formation and six Three Forks first bench formation wells per drilling-spacing unit. We continue to execute an enhanced completion design pilot program, including elevated proppant volumes, hybrid slickwater fracs, increased stages and cemented liners, with 42 of the 55 tests online at the end of 2014.

Our time to drill a well averaged 17 days spud-to-TD in 2014 compared to 15 days in 2013. We reached TD on 83 gross operated wells and brought to sales 67 gross operated wells in 2014 compared to 76 reaching total depth and 77 brought to sales in 2013. We recompleted 35 wells during 2014.

Our net sales from the Bakken shale averaged 51 mboed in 2014, approximately 88 percent crude oil, 6 percent NGLs and 6 percent natural gas, compared to 39 mboed in 2013, a 31 percent increase. In efforts to optimize price realizations, we sell our production in local North Dakota markets and to select purchasers who may elect to transport outside the state.

Approximately 20 percent of our 2015 Budget, $760 million, is allocated to the Bakken. Our 2015 Bakken program includes plans to drill 42 - 53 net wells (100 - 120 gross, of which we will operate 38 - 48). We anticipate bringing 68 - 78 gross operated wells to sales during 2015.

Oklahoma Resource Basins – Our primary focus in 2015 will be in the SCOOP and STACK areas. In the SCOOP area we hold approximately 145,000 net acres with rights to the unconventional Woodford, Springer, Granite Wash and other Pennsylvanian sands plays. We also hold approximately 100,000 net acres in the STACK area with rights to the unconventional Woodford, Meramec and other Mississippian plays. These totals include over 50,000 acres added in the SCOOP and STACK areas in 2014. Though not a focus of the 2015 program, we also hold 57,000 net acres in the broader western Oklahoma Granite Wash and other Pennsylvanian sands plays.

In the SCOOP and STACK areas, we reached total depth on 17 gross operated wells and brought 18 gross operated wells to sales in 2014 compared to 10 reaching total depth and nine brought to sales in 2013. A total of nine net non-operated unconventional wells were brought to sales in 2014 compared to three in 2013.

Sales from our Oklahoma Resource Basins in 2014 were primarily from the Anadarko Woodford shale and averaged 18 mboed, approximately 16 percent crude oil, 28 percent NGLs and 56 percent natural gas, compared to 14 mboed in 2013, a 29 percent increase.

Approximately 6 percent of our 2015 Budget, $226 million, is allocated to the Oklahoma Resource Basins. Our drilling plans for the Oklahoma Resource Basins in 2015 include drilling and completing 17 - 20 net wells (41 - 50 gross of which 16 - 20 are company operated wells). We anticipate bringing 18 - 22 gross operated wells to sales during 2015.

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

Other United States

Gulf of Mexico – Production – On December 31, 2014, we held significant interests in 11 producing fields, four of which are company-operated. Average net sales in 2014 from the Gulf of Mexico were 14 mbbld of liquid hydrocarbons and 16 mmcfd of natural gas, or 17 mboed compared to 19 mboed in 2013. Operational availability for our operated properties was 96 percent, with internal unplanned losses of four 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 50 percent non-operated working interest in the Petronius field on Viosca Knoll Blocks 786 and 830, located 130 miles southeast of New Orleans, which includes 15 producing wells. The Petronius platform is also capable of providing processing and transportation services to nearby third-party fields.

We hold a 30 percent non-operated working interest in the Neptune field located on Atwater Valley Block 575, 120 miles south off the coast of Louisiana. The development includes seven subsea wells tied back to a stand-alone platform. A new Neptune sidetrack well came online late December 2014.

We have an 18 percent non-operated working interest in the Gunflint field development located on Mississippi Canyon Blocks 948, 949, 992(N/2) and 993(N/2), 90 miles south off the coast of Louisiana. 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. The subsea tie-back development project will continue to progress in 2015, with first oil expected in 2016.

Gulf of Mexico – Exploration – We have a 3-year shared contract on the Maersk Valiant drillship and plan to utilize the rig to test prospects in the Gulf of Mexico, including one operated exploration well in 2015. As we evaluate various opportunities for drilling, we may seek partners to further reduce our exploration risk on individual projects.

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 and was successful. The second appraisal well was spud in late May 2014 and the well costs incurred through December 31, 2014 were expensed in the fourth quarter of 2014. A third appraisal well is anticipated to spud on Walker Ridge Block 51 in 2015.

In the fourth quarter of 2014, we drilled two exploratory wells in the Gulf of Mexico: one on the Key Largo prospect, located on Walker Ridge Block 578, in which we have a 60 percent working interest and one on the Perseus prospect, located on Desoto Canyon Block, in which we have a 30 percent non-operated working interest. Neither well encountered commercial hydrocarbons and the well costs incurred through December 31, 2014 were charged to dry well expense. We have no further plans to explore either prospect.

Oklahoma – We have long-established operated and non-operated conventional production in several Oklahoma fields from which sales averaged 8 mboed in 2014 and 9 mboed in 2013.

Texas/North Louisiana/New Mexico – We hold approximately 242,000 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 one gross non-operated well in the Haynesville shale play during 2014. Conventional production was primarily from the Mimms Creek, Pearwood and Haynesville fields in 2014, with net sales averaging 5 mboed in both 2014 and 2013. 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 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. Operated production at the Powder River Basin field ceased in March 2014, and plug and abandonment activities were substantially complete as of December 31, 2014.

Our Wyoming net sales averaged 16 mbbld of liquid hydrocarbons and 11 mmcfd of natural gas, or 18 mboed, during 2014 compared to 22 mboed in 2013. We drilled 11 gross operated development wells in Wyoming 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 approximately142,000 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 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 2015. Upon receiving this approval, we will further evaluate our development plans.

North America E&P--Acquisitions

In an asset acquisition that closed August 2014, we added acreage to our Oklahoma Resource Basins at a cost of approximately $80 million before final settlement adjustments.

In the fourth quarter of 2014, we acquired additional acreage in the SCOOP, at a cost of approximately $60 million before final settlement adjustments.

International E&P Segment

We are engaged in oil and gas exploration, development and/or production activities in E.G., Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq, Libya and the U.K. We 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 2014, E.G. net liquid hydrocarbon sales averaged 31 mbbld and net natural gas sales averaged 439 mmcfd, or 104 mboed, compared to 107 mboed in 2013. Operational availability from our company-operated facilities averaged approximately 98 percent in 2014, 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 eight years is underway and is expected to be operational in 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. The Sodalita West #1 exploratory well was spud during 2014 and reached total depth in February 2015. This well did not encounter commercial hydrocarbons and well costs incurred through December 31, 2014 were charged to dry well expense in the fourth quarter of 2014. A second exploratory well and one Alba field infill well are expected to be drilled in 2015.

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 2014, the gross quantity of natural gas supplied to the LPG production facility was 856 mmcfd, from which 6 mbbld of secondary condensate and 19 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. Gross sales of LNG from this production facility totaled 4 mmta in 2014. Operational availability was 98 percent in 2014, including a planned turnaround, while internal unplanned losses were less than one percent.

AMPCO had gross sales totaling 885 mt in 2014. Operational availability for this methanol plant was 90 percent in 2014, and internal unplanned losses were ten 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 gross acres located in the Sirte Basin of eastern Libya. Beginning in the third quarter of 2013, our Libya operations were impacted by third-party labor strikes at the Es Sider oil terminal. In early July 2014, Libya's National Oil Corporation rescinded force majeure associated with the third-party labor strikes, and our concession term was extended for slightly more than one year. Although we had five liftings during 2014, in December 2014, Libya's National Oil Corporation once again declared force majeure at Es Sider as disruptions from civil unrest continue. Considerable uncertainty remains around the timing of future production and sales levels. We and our partners in the Waha concessions continue to assess the situation and the condition of our assets in Libya. See Item 8. Financial Statements and Supplementary Data – Note 12 to the consolidated financial statements for additional information about our Libya operations.

Gabon – Exploration – We hold a 21.25 percent non-operated working interest in the Diaba License G4-223 and its related permit offshore Gabon, which covers approximately 2.2 million gross (477,000 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. Analysis confirmed dry gas accumulation with minor condensate. Multiple additional pre-salt prospects have been identified on this License. In 2014, 3D seismic acquisition was completed in the western part of the block.

In August 2014, we signed an exploration and production sharing contract for Gabon offshore Block G13, which was subsequently re-named Tchicuate. The block, which is located in the pre-salt play offshore Gabon, encompasses 277,000 acres. The seismic program is expected to be completed in the second quarter of 2015, and processing will occur through the remainder of the year. We hold a 100 percent participating interest and operatorship in the block. In the event of development, the Republic of Gabon will assume a 20 percent financed interest in the contract upon commencement of production. The State holds additional rights to participate in the block in the future as a co-investor.

Kenya – Exploration – We hold a 50 percent non-operated working interest in Block 9, consisting of approximately 3.9 million gross (1.9 million net) acres in northwest Kenya. The Sala-1 exploration well was spud in February 2014 on the eastern side of Block 9 and made a natural gas discovery in the second quarter of 2014. The well was drilled to a total depth of approximately 10,000 feet, and analysis indicated three zones of interest over a 3,280-foot gross interval which were subsequently drill-stem tested. The Sala-2 appraisal well spud in the third quarter of 2014, but did not encounter commercial hydrocarbons, and the well costs were charged to dry well expense. We hold a 50 percent non-operated working interest in Block 9 with the option to operate any commercial development.

We also hold a 15 percent non-operated working interest in Block 12A, covering approximately 3.8 million gross (566,000 net) acres, which is also located in northwest Kenya. The acquisition of 2D seismic on Block 12A began in 2013 and was completed in 2014. Multiple prospects have been identified and the first exploratory well is anticipated to be drilled in late 2015.

Ethiopia – Exploration – We hold a 20 percent non-operated working 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. Two wells were drilled on the South Omo Block in 2014: the Shimela-1 well, which reached total depth in May 2014, and the Gardim-1 well, which reached total depth in July 2014. Neither well encountered commercial hydrocarbons and the well costs were charged to dry well expense during 2014.

We have a 50 percent non-operated working interest in the Rift Basin Area Block with approximately 10.5 million gross acres. We began 2D seismic acquisition in the first quarter of 2015 in order to develop prospect inventory for a future drilling program. We have the option to operate if a discovery is made.

Other – An outbreak of the Ebola virus has existed in certain regions of West Africa (Guinea, Liberia, Sierra Leone) since late 2013. Although neither E.G. nor any other African country in which we have business activities has been impacted by Ebola to date, our business operations may be adversely affected through travel or other restrictions. We continue to monitor the situation, have enhanced our emergency response plans to address any potential impact, and are working closely with appropriate external parties to maintain business continuity and the health and well-being of our staff.

Other International

United Kingdom – Net sales from the U.K. averaged 11 mbbld of liquid hydrocarbons and 28 mmcfd of natural gas, or 16 mboed, in 2014 compared to 20 mboed 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. Operational availability in 2014 for the Brae complex was 90 percent and internal unplanned losses were nine percent. We brought two South Brae infill wells online late in the second half of 2014 and plan to complete two West Brae subsea wells and one additional South Brae infill well in 2015.

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 31 third-party fields are contracted to use the Brae system and 72 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 non-operated interest in the 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 non-operated working interests in the 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 an FPSO to market. All natural gas sales are to the non-operated Magnus platform for use as injection gas.

Croatia – We were awarded, as part of a consortium, seven blocks located offshore in the Adriatic Sea, subject to negotiation of a PSC with the Croatian Government. We have a 60 percent interest in the consortium.

Kurdistan Region of Iraq – In aggregate, we have approximately 109,000 net acres in the Kurdistan Region of Iraq. We have a 45 percent operated working interest in the Harir block located northeast of Erbil. For a short time in 2014, we suspended certain operations due to security concerns in the region and continue to closely monitor the situation. We also have non-operated interests in two blocks located north-northwest of Erbil: Atrush with 15 percent working interest and Sarsang with 20 percent working interest.

On the non-operated Atrush block, following the successful appraisal program and a declaration of commerciality, the Kurdistan Ministry of Natural Resources approved a plan for field development in September 2013. The development project consists of drilling three production wells and constructing a central processing facility in Phase 1 which provides for a 25-year production period. We expect first production in late 2015 with estimated initial gross production of approximately 30 mbbld of oil. 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. The Atrush-3 appraisal well, within the potential Phase 2 development area approximately four miles east of existing wells, confirmed the extension of the oil bearing reservoirs in 2013 and has been suspended as a potential future producer.

On the non-operated Sarsang block, the Swara Tika discovery was declared commercial in May 2014 and a field development plan was filed in June 2014. Currently, the East Swara Tika-1 exploration well is being sidetracked up-dip. Discussions are ongoing with the Ministry of Natural Resources to finalize the Swara Tika field development plan.

On the operated Harir block, we spud the Mirawa-2 appraisal well in December 2014 which is expected to reach total depth in the second quarter of 2015. In December 2014, we announced the Jisik-1 discovery and in 2013, the Mirawa-1 discovery. Both the Jisik-1 and Mirawa-1 exploratory wells had discovered multiple stacked oil and natural gas producing zones, and have been suspended for potential future use as producing wells.

Acquisitions and Dispositions

In the fourth quarter of 2014, we closed the sale of our Norway business, including the operated Alvheim FPSO, 10 operated licenses and a number of non-operated licenses on the Norwegian Continental Shelf in the North Sea, with an effective date of January 1, 2014 for proceeds of approximately $2.1 billion.

In the first quarter of 2014, we closed the sales of our 10 percent non-operated working interests in the Production Sharing Contracts and Joint Operating Agreements for Angola Blocks 31 and 32 for aggregate proceeds of approximately $2 billion. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements for additional information about these dispositions, including discontinued operations presentation.

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, 2014, 2013 and 2012 and drilling wells as of December 31, 2014.

	Productive Wells[(a)]							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2014								
U.S.	7,058	2,919	2,246	1,023	2,638	760	45	25
E.G.	—	—	16	11	2	1	—	—
Other Africa	1,071	175	7	1	94	16	3	1
Total Africa	1,071	175	23	12	96	17	3	1
Other International	55	20	39	16	24	8	6	2
Total	8,184	3,114	2,308	1,051	2,758	785	54	28
2013								
U.S.	6,632	2,568	2,763	1,482	2,349	744		
E.G.	—	—	16	11	2	1		
Other Africa	1,072	175	7	1	99	16		
Total Africa	1,072	175	23	12	101	17		
Other International	77	34	40	16	28	11		
Total	7,781	2,777	2,826	1,510	2,478	772		
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		
Other International	77	34	40	16	28	11		
Total	7,318	2,520	3,268	1,932	2,461	766		

(a) Of the gross productive wells, wells with multiple completions operated by us totaled 31, 31 and 115 as of December 31, 2014, 2013 and 2012. Information on wells with multiple completions operated by others is unavailable to us.

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				
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	Total
Year Ended December 31, 2014									
U.S.	253	43	1	297	49	19	4	72	369
Africa	1	—	—	1	—	—	2	2	3
Other International	1	—	—	1	—	—	—	—	1
Total	255	43	1	299	49	19	6	74	373
Year Ended December 31, 2013									
U.S.	237	20	—	257	73	13	3	89	346
Africa	4	—	—	4	1	—	2	3	7
Other International	—	—	—	—	—	—	3	3	3
Total	241	20	—	261	74	13	8	95	356
Year Ended December 31, 2012									
U.S.	172	21	2	195	117	13	9	139	334
Africa	4	—	—	4	1	—	—	1	5
Other International	3	—	—	3	—	—	—	—	3
Total	179	21	2	202	118	13	9	140	342

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 combined as of December 31, 2014.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
U.S.	1,822	1,408	1,036	865	2,858	2,273
Canada	—	—	142	54	142	54
Total North America	1,822	1,408	1,178	919	3,000	2,327
E.G.	45	29	183	164	228	193
Other Africa	12,909	2,108	26,145	9,612	39,054	11,720
Total Africa	12,954	2,137	26,328	9,776	39,282	11,913
Other International	94	33	346	110	440	143
Total	14,870	3,578	27,852	10,805	42,722	14,383

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.

	Net Undeveloped Acres Expiring		
	Year Ended December 31,		
(In thousands)	2015	2016	2017
U.S.	211	150	94
E.G.	36	—	—
Other Africa	1,950	1,502	1,089
Total Africa	1,986	1,502	1,089
Other International	88	—	—
Total	2,285	1,652	1,183

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 located 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, 2014, we own or have rights to participate in developed and undeveloped leases totaling approximately 163,000 gross (33,000 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 2014 averaged 50 mbbld and net-of-royalty production was 41 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 evaluate the potential expansion project and government conditions after infrastructure reliability initiatives are completed.

The governments of Alberta and Canada have agreed to partially fund Quest CCS for $865 million Canadian. 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 commenced in 2012 and continued as milestones were 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.

Reserves

Estimated Reserve Quantities

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. Other International ("Other Int'l"), includes the U.K. and the Kurdistan Region of Iraq. We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014, and both are shown as discontinued operations ("Disc Ops") for all periods presented. Approximately 76 percent of our proved reserves are located in OECD countries.

Our December 31, 2014 proved reserves were calculated using the unweighted average of closing prices for the first day of each month in 2014 within the 12-month period. The 2014 unweighted averages for certain of the benchmark prices were as follows:

- WTI crude oil - $94.99 per bbl
- Henry Hub natural gas - $4.31 per mmbtu
- Brent crude oil - $101.39 per bbl

When determining the December 31, 2014 proved reserves for each property, the benchmark prices listed above were adjusted with price differentials that account for property-specific quality and location differences. Beginning in the second half of 2014, the crude oil benchmarks began to decline and this decline continued into early 2015. In addition, the Henry Hub natural gas benchmark began to decline in late 2014 and continued its decline into 2015. Commodity prices are likely to remain volatile based on global supply and demand and could decline further. The January 2015 benchmark closing prices for the first day of the month were WTI crude oil of $52.69 per bbl, Henry Hub natural gas of $2.99 per mmbtu and Brent crude oil of $55.55 per bbl. Sustained reduced commodity prices could have a material effect on the quantity and future cash flows of our proved reserves. To the extent that we experience a sustained period of reduced commodity prices in 2015, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Estimates of future cash flows associated with proved reserves are based on actual costs of developing and producing the reserves as of the end of the year. The decline in commodity prices experienced in the second half of 2014 has resulted in a reduction in the costs of developing and producing reserves. The impact of sustained reduced commodity prices on future cash flows will be partially offset by the impact of lower costs.

A sustained period of lower commodity prices could also cause us to decrease our near term capital programs and defer investment until prices improve. A shifting of capital expenditures into future periods outside of five years from the initial proved reserve booking could potentially lead to a reduction in proved undeveloped reserves. See Item 1A. Risk Factors for a further discussion of how a substantial extended decline in commodity prices could impact us.

The most significant increase in total proved reserves from 2013 to 2014 related to our U.S. unconventional shale plays, while sales of reserves in place related to our Norway and Angola discontinued operations were the largest decreases in 2014 proved reserves. Excluding discontinued operations, total proved reserves related to continuing operations increased 133 mmboe primarily due to drilling programs in our U.S. unconventional shale plays and additions in E.G. and the Kurdistan Region of Iraq, offset by production. In the U.S., we added 288 mmboe in 2014, excluding purchases and sales of reserves in place and production, amounting to an increase of 37 percent over the 2013 ending balance, mainly due to downspacing, drilling activity and improved well performance. The negative 55 mmboe revision to Canadian synthetic crude oil reserves primarily reflects the impact of technical and price changes on calculated royalty volumes as well as development plan changes in the mineable areas. See Item 8. Financial Statements and Supplementary Data - Supplementary Information on Oil and Gas Producing Activities for more information.

The following tables set forth estimated quantities of our proved crude oil and condensate, NGL, 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, 2014, 2013 and 2012.

December 31, 2014	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Other Int'l	Cont Ops	Disc Ops	Total
Proved Developed Reserves										
Crude oil and condensate *(mmbbl)*	294	—	294	30	175	205	19	518	—	518
Natural gas liquids *(mmbbl)*	68	—	68	15	—	15	—	83	—	83
Natural gas *(bcf)*	575	—	575	664	94	758	17	1,350	—	1,350
Synthetic crude oil *(mmbbl)*	—	644	644	—	—	—	—	644	—	644
Total proved developed reserves *(mmboe)*	458	644	1,102	155	191	346	22	1,470	—	1,470
Proved Undeveloped Reserves										
Crude oil and condensate (*mmbbl*)	340	—	340	27	33	60	10	410	—	410
Natural gas liquids (*mmbbl*)	93	—	93	15	—	15	1	109	—	109
Natural gas (*bcf*)	569	—	569	541	115	656	5	1,230	—	1,230
Synthetic crude oil *(mmbbl)*	—	4	4	—	—	—	—	4	—	4
Total proved undeveloped reserves (*mmboe*)	528	4	532	133	52	185	11	728	—	728
Total Proved Reserves										
Crude oil and condensate (*mmbbl*)	634	—	634	57	208	265	29	928	—	928
Natural gas liquids (*mmbbl*)	161	—	161	30	—	30	1	192	—	192
Natural gas (*bcf*)	1,144	—	1,144	1,205	209	1,414	22	2,580	—	2,580
Synthetic crude oil (*mmbbl*)	—	648	648	—	—	—	—	648	—	648
Total proved reserves (*mmboe*)	986	648	1,634	288	243	531	33	2,198	—	2,198

December 31, 2013	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Other Int'l	Cont Ops	Disc Ops	Total
Proved Developed Reserves										
Crude oil and condensate *(mmbbl)*	241	—	241	37	176	213	19	473	77	550
Natural gas liquids *(mmbbl)*	51	—	51	18	—	18	1	70	—	70
Natural gas *(bcf)*	540	—	540	823	95	918	21	1,479	20	1,499
Synthetic crude oil *(mmbbl)*	—	674	674	—	—	—	—	674	—	674
Total proved developed reserves *(mmboe)*	382	674	1,056	193	192	385	23	1,464	80	1,544
Proved Undeveloped Reserves										
Crude oil and condensate *(mmbbl)*	256	—	256	27	39	66	6	328	14	342
Natural gas liquids *(mmbbl)*	68	—	68	16	—	16	—	84	—	84
Natural gas *(bcf)*	485	—	485	497	110	607	7	1,099	73	1,172
Synthetic crude oil *(mmbbl)*	—	6	6	—	—	—	—	6	—	6
Total proved undeveloped reserves *(mmboe)*	405	6	411	125	57	182	8	601	26	627
Total Proved Reserves										
Crude oil and condensate *(mmbbl)*	497	—	497	64	215	279	25	801	91	892
Natural gas liquids *(mmbbl)*	119	—	119	34	—	34	1	154	—	154
Natural gas *(bcf)*	1,025	—	1,025	1,320	205	1,525	28	2,578	93	2,671
Synthetic crude oil *(mmbbl)*	—	680	680	—	—	—	—	680	—	680
Total proved reserves *(mmboe)*	787	680	1,467	318	249	567	31	2,065	106	2,171

December 31, 2012	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Other Int'l	Cont Ops	Disc Ops	Total
Proved Developed Reserves										
Crude oil and condensate *(mmbbl)*	169	—	169	45	168	213	20	402	63	465
Natural gas liquids *(mmbbl)*	29	—	29	23	—	23	1	53	—	53
Natural gas *(bcf)*	546	—	546	980	99	1,079	8	1,633	20	1,653
Synthetic crude oil *(mmbbl)*	—	653	653	—	—	—	—	653	—	653
Total proved developed reserves *(mmboe)*	289	653	942	231	185	416	22	1,380	66	1,446
Proved Undeveloped Reserves										
Crude oil and condensate *(mmbbl)*	218	—	218	27	41	68	4	290	19	309
Natural gas liquids *(mmbbl)*	59	—	59	15	—	15	—	74	—	74
Natural gas *(bcf)*	497	—	497	444	110	554	6	1,057	69	1,126
Synthetic crude oil *(mmbbl)*	—	—	—	—	—	—	—	—	—	—
Total proved undeveloped reserves *(mmboe)*	360	—	360	116	59	175	5	540	31	571
Total Proved Reserves										
Crude oil and condensate *(mmbbl)*	387	—	387	72	209	281	24	692	82	774
Natural gas liquids *(mmbbl)*	88	—	88	38	—	38	1	127	—	127
Natural gas *(bcf)*	1,043	—	1,043	1,424	209	1,633	14	2,690	89	2,779
Synthetic crude oil *(mmbbl)*	—	653	653	—	—	—	—	653	—	653
Total proved reserves *(mmboe)*	649	653	1,302	347	244	591	27	1,920	97	2,017

Preparation of Reserve Estimates

All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X. Crude oil and condensate, NGL, 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. Crude oil and condensate, NGL, and natural gas reserve estimates are developed or reviewed by Qualified Reserves Estimators ("QREs"). QREs are engineers or geoscientists who hold 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. Our Corporate Reserves group screens all fields with net 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 Vice President, Operations Services, has a Bachelor of Science degree in petroleum engineering and is a registered Professional Engineer in the State of Texas. In his 27 years with Marathon Oil, he has held numerous engineering and management positions, including 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 individual responsible for the estimates of our synthetic crude oil reserves has 14 years of experience in petroleum engineering, has conducted surface mineable oil sands evaluations since 2009 and is a registered Practicing Professional Engineer in the Province of Alberta.

Audits of Estimates

Third-party consultants are engaged to provide independent estimates for fields that comprise 80 percent of our total proved reserves over a rolling four-year period for the purpose of auditing and validating our internal reserve estimates. We exceeded this percentage for the four-year period ended December 31, 2014. We have established a tolerance level of 10 percent such that initial estimates by the third-party consultants for each field 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 2014, 2013 or 2012.

During 2014, 2013 and 2012, 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 multiple 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 15 years experience in the estimation and evaluation of reserves. The second team member has over 10 years of practical experience in petroleum engineering, with 5 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 the prior years' reserves of several of our fields in 2014, 2013 and 2012. Their summary reports are filed as exhibits to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 20 years of industry experience, having worked for a major international oil and gas company before joining Ryder Scott. He 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, 2014, 728 mmboe of proved undeveloped reserves were reported, an increase of 101 mmboe from December 31, 2013. The following table shows changes in total proved undeveloped reserves for 2014:

(mmboe)	
Beginning of year	627
Revisions of previous estimates	1
Improved recovery	1
Purchases of reserves in place	4
Extensions, discoveries, and other additions	227
Dispositions	(29)
Transfers to proved developed	(103)
End of year	728

Significant additions to proved undeveloped reserves during 2014 included 121 mmboe in the Eagle Ford and 61 mmboe in the Bakken shale plays due to development drilling. Transfers from proved undeveloped to proved developed reserves included 67 mmboe in the Eagle Ford, 26 mmboe in the Bakken and 1 mmboe in the Oklahoma Resource Basins due to development drilling and completions. Costs incurred in 2014, 2013 and 2012 relating to the development of proved undeveloped reserves, were $3,149 million, $2,536 million and $1,995 million.

A total of 102 mmboe was booked as extensions, discoveries or other additions due to the application of reliable technology. Technologies included statistical analysis of production performance, decline curve analysis, pressure and 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 proved 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 728 mmboe of proved undeveloped reserves at December 31, 2014, 19 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 in the second quarter of 2015.

Proved undeveloped reserves for the North Gialo development, located in the Libyan Sahara desert, were booked for the first time in 2010. This development, which is anticipated to take more than five years to develop, is executed by the operator and encompasses a multi-year 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 lead to an expected project execution time frame 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 and civil unrest in 2013-2014 have also extended the project duration.

As of December 31, 2014, future development costs estimated to be required for the development of proved undeveloped crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves related to continuing operations for the years 2015 through 2019 are projected to be $2,915 million, $2,598 million, $2,493 million, $2,669 million and $2,745 million.

Net Production Sold

	North America			Africa					
	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Disc Ops	Total
Year Ended December 31,									
2014									
Crude and condensate *(mbbld)*[a]	157	—	157	21	7	28	11	48	244
Natural gas liquids *(mbbld)*	29	—	29	10	—	10	—	—	39
Natural gas *(mmcfd)*[b]	310	—	310	439	1	440	21	37	808
Synthetic crude oil *(mbbld)*[c]	—	41	41	—	—	—	—	—	41
Total production sold *(mboed)*	238	41	279	104	7	111	15	54	459
2013									
Crude and condensate *(mbbld)*[a]	126	—	126	23	24	47	14	81	268
Natural gas liquids *(mbbld)*	23	—	23	11	—	11	1	—	35
Natural gas *(mmcfd)*[b]	312	—	312	442	22	464	25	51	852
Synthetic crude oil *(mbbld)*[c]	—	42	42	—	—	—	—	—	42
Total production sold *(mboed)*	201	42	243	107	27	134	20	89	486
2012									
Crude and condensate *(mbbld)*[a]	96	—	96	25	42	67	15	81	259
Natural gas liquids *(mbbld)*	11	—	11	11	—	11	1	—	23
Natural gas *(mmcfd)*[b][d]	358	—	358	428	15	443	33	53	887
Synthetic crude oil *(mbbld)*[c]	—	41	41	—	—	—	—	—	41
Total production sold *(mboed)*	166	41	207	108	44	152	21	90	470

(a) The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.
(b) Excludes volumes acquired from third parties for injection and subsequent resale.
(c) Upgraded bitumen excluding blendstocks.
(d) U.S. natural gas volumes exclude volumes produced in Alaska that were stored for later sale in response to seasonal demand, although our reserves had been reduced by those volumes.

Average Sales Price per Unit

	North America			Africa					
(Dollars per unit)	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Disc Ops	Total
2014									
Crude and condensate *(bbl)*	$ 85.25	$ —	$ 85.25	$ 81.01	$ 94.70	$ 84.48	$ 94.31	$109.80	$ 90.37
Natural gas liquids *(bbl)*	33.42	—	33.42	1.00 [a]	—	1.00	67.73	—	25.25
Natural gas *(mcf)*	4.57	—	4.57	0.24 [a]	3.11	0.25	8.27	9.94	2.55
Synthetic crude oil *(bbl)*	—	83.35	83.35	—	—	—	—	—	83.35
2013									
Crude and condensate *(bbl)*	$ 94.19	$ —	$ 94.19	$ 90.62	$122.92	$107.31	$110.76	$112.36	$102.81
Natural gas liquids *(bbl)*	35.12	—	35.12	1.00 [a]	—	1.00	72.14	—	24.78
Natural gas *(mcf)*	3.84	—	3.84	0.24 [a]	5.44	0.49	10.64	13.01	2.75
Synthetic crude oil *(bbl)*	—	87.51	87.51	—	—	—	—	—	87.51
2012									
Crude and condensate *(bbl)*	$ 91.30	$ —	$ 91.30	$ 92.56	$127.31	$114.52	$109.50	$116.70	$106.35
Natural gas liquids *(bbl)*	39.57	—	39.57	1.00 [a]	—	1.00	78.81	—	23.44
Natural gas *(mcf)*	3.92	—	3.92	0.24 [a]	5.76	0.43	9.72	11.15	2.80
Synthetic crude oil *(bbl)*	—	81.72	81.72	—	—	—	—	—	81.72

(a) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and/or 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	Total	Africa E.G.	Other	Total	Other Int'l	Disc Ops	Total
2014	$ 13.34	$ 46.63	$ 18.73	$ 4.03	N.M.	$ 5.72	$ 47.06	$ 8.92	$ 15.37
2013	13.60	55.42	20.79	2.88	7.40	3.80	38.87	8.24	14.51
2012	13.61	53.61	21.51	3.59	3.57	3.59	28.33	5.55	12.98

(a) Production, severance and property taxes are excluded; however, shipping and handling as well as other operating expenses are included in 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 costs.

N.M. Not meaningful information due to limited sales in 2014.

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, 2014, those contracts for fixed and determinable quantities were at variable, market-based pricing and related primarily to liquid hydrocarbon production in the Eagle Ford and Bakken, and OSM synthetic crude oil production. Eagle Ford liquid hydrocarbon production sales commitments range from a minimum of 76 mbbld increasing to 113 mbbld in 2015 through 2018 and 51 mbbld to 65 mbbld in 2019 through 2020. Bakken liquid hydrocarbon production sales commitments of 10 mbbld commence in the fourth quarter of 2016 and expire June 1, 2026. Synthetic crude oil production sales commitments fall under a 3-year agreement for 13.5 mbbld which expires July 2017. Our current production rates, forecasts and proved reserves are sufficient to meet these commitments. All of these contracts provide the options of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate.

In addition to the sales contracts discussed above, we have entered into numerous agreements for transportation and processing of our equity production. Some of these contracts have volumetric requirements which could require monetary shortfall penalties if our production is inadequate to meet the terms.

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 "2014 Global Upstream Performance Review" published by IHS Inc., we rank tenth among U.S.-based petroleum companies on the basis of 2013 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 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, may result in a significant increase in the supply of synthetic crude oil to the market. Because not all refineries are able to process or refine synthetic crude oil in significant volumes, sufficient market demand may not 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 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 liquid hydrocarbons and natural gas 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 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 and Climate Change

The EPA proposed a more stringent National Ambient Air Quality Standard (NAAQS) for ozone in December 2014. 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 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.

In August 2012, the 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 with a compliance deadline of January 1, 2015. While these rules remain in effect, the EPA announced in 2013 that it would reexamine and reissue the rules over the next three years. The EPA has issued updated rules regarding storage tanks and additional rules are expected. In December 2014, the EPA issued finalized additional amendments to these rules that, among other things, distinguished between multiple flowback stages during completion of hydraulically fractured wells and clarified that storage tanks permanently removed from service are not affected by any requirements. Further, in 2012, seven states sued the EPA to compel the agency to make a determination as to whether standards of performance limiting methane emissions from oil and gas sources is appropriate and, if so, to promulgate performance standards for methane emissions from existing oil and gas sources. In April 2014, the EPA released a set of five white papers analyzing methane emissions from the industry, and, based on responses received, announced in early 2015 that it will begin the process of issuing a rule governing methane emissions from the oil and gas industry. If we are unable to comply with air pollution regulations or to obtain permits for emissions associated with our operations, we could be required to forego construction, modification or certain operations. These regulations may also increase compliance costs for some facilities we own or operate, and result in administrative, civil and/or criminal penalties for non-compliance. Obtaining permits may delay the development of our oil and natural gas projects, including the construction and operation of facilities.

In 2010, the 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 (see discussion above regarding potential methane regulation by EPA). 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 and local level through permitting and compliance requirements. State and local 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. Further, the Bureau of Land Management is expected to issue a rule governing certain hydraulic fracturing practices on lands within their jurisdiction in early 2015. 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 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 EPA issued a progress report in late 2012, and expects to issue a draft report for public comment and peer review in 2015, 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 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, state or local 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.

Transportation

A number of state and federal rules apply to the transportation of liquid hydrocarbons. In 2014, the U.S. Department of Transportation ("DOT") proposed a rule relating to testing and classification of liquid hydrocarbons and imposing additional restrictions on the types of rail cars that may be used in certain types of liquid hydrocarbon service. Although our businesses do not own rail cars and purchasers of our liquid hydrocarbons make arrangements for its transportation, such regulations could increase transportation costs which are passed on to Marathon Oil by liquid hydrocarbon purchasers. We anticipate a final rule sometime in 2015. In addition, the Pipeline and Hazardous Materials Safety Administration, a sub-agency of DOT, has proposed or announced the intention to propose various rules related to pipeline transportation of natural gas and/or liquid hydrocarbons. Such regulations could increase the regulatory burden on our businesses where we own or operate pipelines, or could otherwise increase costs to third parties that are passed on to Marathon Oil.

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.

Water

In 2014, the EPA and the U.S. Army Corps of Engineers published proposed regulations which expand the surface waters that are regulated under the Clean Water Act and its various programs. If finalized as proposed, this expansion will result in additional costs of compliance as well as increased monitoring, recordkeeping, and recording for some of our facilities.

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 2014, sales to Shell Oil and its affiliates accounted for approximately 10 percent of our total revenues. For 2013, sales to Statoil, the purchaser of the majority of our Libyan crude oil, accounted for approximately 10 percent of our annual revenues. For 2012, sales to Statoil accounted for approximately 15 percent of our total revenues, while sales to Shell Oil and its affiliates accounted for approximately 12 percent of our annual revenues.

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 3,330 active, full-time employees as of December 31, 2014. 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, 2015, are as follows:

Lee M. Tillman	53	President and Chief Executive Officer
John R. Sult	55	Executive Vice President and Chief Financial Officer
Sylvia J. Kerrigan	49	Executive Vice President, General Counsel and Secretary
T. Mitch Little	51	Vice President, International and Offshore Production Operations
Lance W. Robertson	42	Vice President, North America Production Operations
Patrick J. Wagner	50	Vice President, Corporate Development
Gary E. Wilson	53	Vice President, Controller and Chief Accounting Officer

Mr. Tillman was appointed president and chief executive officer in 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 (a project design and execution company), where he was responsible for all global engineering staff engaged in major project concept selection, front-end design and engineering. Between 2007 and 2010, Mr. Tillman served as North Sea production manager and lead country manager for subsidiaries of ExxonMobil 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 in September 2013. Prior to joining Marathon Oil, Mr. Sult served as executive vice president and chief financial officer of El Paso Corporation (a natural gas provider) from 2010 through 2012, senior vice president and chief financial officer from 2009 to 2010, and senior vice president, chief accounting officer and controller from 2005 to 2009.

Ms. Kerrigan was appointed executive vice president, general counsel and secretary in October 2012, having served as vice president, general counsel and secretary since November 2009. Prior to these appointments, Ms. Kerrigan served as assistant general counsel since January 2003.

Mr. Little was appointed vice president, international and offshore exploration and production operations in September 2013, having served as vice president, international production operations since September 2012. Prior to that, 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 since held a number of engineering and management positions of increasing responsibility.

Mr. Robertson was appointed vice president, North America production operations in September 2013, having 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 Company (an independent oil and gas company) in the U.S. and Canada.

Mr. Wagner was appointed vice president, corporate development in April 2014. Prior to joining Marathon Oil, he served as senior vice president, western business unit, for QR Energy LP (an oil and natural gas producer) and the affiliated Quantum Resources Management (a private equity firm), which he joined in early 2012 as vice president, exploitation. Prior to that, Wagner was managing director in Houston for Scotia Waterous, the oil and gas arm of Scotiabank (an international banking services provider), from 2010 to 2012. Before joining Scotia, Wagner was vice president, Gulf of Mexico, for Devon Energy Corp. (an oil and natural gas producer), having joined Devon in 2003 as manager, international exploitation.

Mr. Wilson was appointed vice president, controller and chief accounting officer in October 2014. Prior to joining Marathon Oil, he served in various finance and accounting positions of increasing responsibility at Noble Energy, Inc. (a global exploration and production company) since 2001, including as director corporate accounting from February 2014 through September 2014, director global operations services finance from October 2012 through February 2014, director controls and reporting from April 2011 through September 2012, and international finance manager from September 2009 through March 2011.

Available Information

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

The public may read and copy any materials we file with the SEC at its Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Additionally, we make available free of charge on our website:

- our Code of Business Conduct and Code of Ethics for Senior Financial Officers;
- our Corporate Governance Principles; and
- the charters of our Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and Health, Environmental, Safety and Corporate Responsibility Committee.

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 crude oil and condensate, NGLs, natural gas and synthetic crude oil fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil and condensate, NGLs, natural gas and synthetic crude oil. Historically, the markets for crude oil and condensate, NGLs, natural gas and synthetic crude oil have been volatile and may continue to be volatile in the future. For example, beginning in the second half of 2014 and continuing into 2015, the WTI and Brent crude oil benchmarks have substantially declined. In addition, the Henry Hub natural gas benchmark began to decline in late 2014 and continued its decline into 2015. Many of the factors influencing prices of crude oil and condensate, NGLs, natural gas and synthetic crude oil are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- the cost of exploring for, developing and producing crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- the ability of the members of OPEC to agree to and maintain production controls;
- the level of drilling, completion and production activities by other exploration and production companies, and variability therein, in response to market conditions;
- 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;
- epidemics or pandemics;
- technological advances affecting energy consumption and energy supply;
- 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil are uncertain. Prolonged or substantial declines in commodity prices could have adverse effects on our business, including:

- reducing the amount of crude oil and condensate, NGLs, natural gas and synthetic crude oil that we can produce economically;
- reducing our revenues, operating income and cash flows;
- causing us to reduce our capital expenditures, or delay or postpone some of our capital projects, resulting in lower production of crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- requiring us to impair the carrying value of our assets;
- reducing the amounts of our estimated proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves that we may produce economically;
- reducing the standardized measure of discounted future net cash flows relating to crude oil and condensate, NGLs, natural gas and synthetic crude oil; and
- limiting our access to sources of capital, such as equity and long-term debt and/or increasing the costs of obtaining such capital.

A substantial, extended decline in liquid hydrocarbon or natural gas prices could adversely affect the abilities of our counterparties to perform their obligations to us, which could negatively impact our financial results.

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production, oil sands mining or liquid hydrocarbon or natural gas transportation, with partners and other counterparties in order to share risks associated with those operations. In addition, we market our products to a variety of purchasers. If commodity prices remain at or fall below current levels, some of our counterparties may experience liquidity problems and may not be able to meet their financial obligations to us. The inability of our joint venture partners to fund their portion of the costs under our joint venture agreements, or the nonperformance by purchasers, contractors or other counterparties of their obligations to us, could negatively impact our financial results.

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 crude oil and condensate, NGLs, 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 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, 2014, 2013 and 2012, as well as other conditions in existence at those dates. For 2014, the average of closing prices for the first day of each month in the 12-month period were WTI crude oil of $94.99 per bbl, Henry Hub natural gas of $4.31 per mmbtu and Brent crude oil of $101.39 per bbl. Any significant future price change could have a material effect on the quantity and present value of our proved reserves. The January 2015 benchmark closing prices for the first day of the month were WTI crude oil of $52.69 per bbl, Henry Hub natural gas of $2.99 per mmbtu and Brent crude oil of $55.55 per bbl. To the extent that we experience a sustained period of reduced commodity prices in 2015, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Future reserve revisions could also result from changes in governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of crude oil and condensate, NGLs, 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 crude oil and condensate, NGLs, 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 crude oil and condensate, NGLs, 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, 2014, 2013 and 2012, 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil are produced. Accordingly, to the extent we are not successful in replacing the crude oil and condensate, NGLs, natural gas and synthetic crude oil 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil 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 crude oil and condensate, NGLs 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 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. Our operations result in these greenhouse gas emissions. 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. Internationally, member countries that have ratified the Kyoto Protocol have made additional commitments to reduce greenhouse gas emissions. The U.S. has not ratified the Kyoto protocol, but may do so in the future. The EPA has announced its intention to specifically regulate methane emissions from the oil and gas industry. Finalization of new legislation, regulations or international agreements in the future 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil, and create delays in our obtaining air pollution permits for new or modified facilities.

The potential adoption of federal, state and local 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. Federal, state and local-level laws or regulations targeting various aspects of the hydraulic fracturing process are being considered, or have been proposed or implemented. For example, the U.S. Congress has considered legislation that would require additional regulation affecting the hydraulic fracturing process, and may be expected to do so in future legislative sessions. Further, various state and local-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 to such legislative and regulatory proposals, there are also a number of studies and initiatives underway that may lead to additional proposals in the future, such as the EPA research study on the potential effects that hydraulic fracturing may have on water quality and public health.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and condensate, NGLs and natural gas, including from the shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local 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 41 percent of our liquid hydrocarbon and natural gas sales volumes related to continuing operations in 2014 was derived from production outside the U.S. and 55 percent of our proved crude oil and condensate, NGLs and natural gas reserves as of December 31, 2014 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 or other armed conflict 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, armed conflict 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.

For the past several years, there have been varying degrees of political instability and public protests, including demonstrations which have been marked by violence and numerous incidences of terrorist acts, 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, or other armed conflict, 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil. 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 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil, which could increase the costs and/or reduce the revenues we might obtain from the sale of our production. Both the cost and availability of pipelines, rail cars, trucks, or vessels to transport our crude oil could be adversely impacted by new and expected state or federal regulations relating to transportation of crude oil.

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 liquid hydrocarbon 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 liquid hydrocarbon 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 liquid hydrocarbon 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, or oil sands mining, 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 crude oil and condensate, NGLs, natural gas, and synthetic crude oil sales volumes are set forth in Item 8. Financial Statements and Supplementary Data – Supplemental Statistics. Estimated net proved crude oil and condensate, NGLs, 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.

Environmental Proceedings

The following is a summary of proceedings involving us that were pending or contemplated as of December 31, 2014 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, 2014, 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 have approximately $6 million accrued to address the clean-up and remediation costs connected with these sites.

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 February 23, 2015, there were 39,772 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:

	2014			2013		
(Dollars per share)	High Price	Low Price	Dividends	High Price	Low Price	Dividends
First Quarter	$35.52	$31.81	$0.19	$35.71	$31.59	$0.17
Second Quarter	$40.16	$34.90	$0.19	$36.38	$29.85	$0.17
Third Quarter	$41.69	$37.59	$0.21	$37.83	$32.61	$0.19
Fourth Quarter	$37.13	$24.80	$0.21	$37.93	$34.06	$0.19
Full Year	$41.69	$24.80	$0.80	$37.93	$29.85	$0.72

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

The following table provides information about purchases by Marathon Oil and its affiliated purchaser, during the quarter ended December 31, 2014, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934:

	Column (a)	Column (b)	Column (c)	Column (d)
Period	Total Number of Shares Purchased[a]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[c]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[c]
10/01/14 – 10/31/14	56,595	$36.55	—	$ 1,500,285,529
11/01/14 – 11/30/14	3,699	$35.12	—	$ 1,500,285,529
12/01/14 – 12/31/14	39,002 [b]	$26.70	—	$ 1,500,285,529
Total	99,296	$32.63	—	

(a) 62,242 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) 37,054 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 plan administrator. Shares needed to meet the requirements of the Dividend Reinvestment Plan may either be purchased in the open market or issued directly by Marathon Oil.

(c) As of December 31, 2014, we had purchased a total of 121 million common shares under the plan at a cost of $4.7 billion, which includes transaction fees and commissions that are not reported in the table above. Of this total, 29 million shares were acquired at a cost of $1 billion in the first and second quarters of 2014, 14 million shares 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 at a cost of $2,922 million prior to the June 30, 2011 spin-off of our downstream business. The remaining share repurchase authorization as of December 31, 2014 is $1.5 billion.

Item 6. Selected Financial Data

	Year Ended December 31,				
(In millions, except per share data)	2014[a][b]	2013[a][b]	2012[a][b]	2011[a][b]	2010 [a][b]
Statement of Income Data					
Revenues	$ 10,846	$ 11,325	$ 11,966	$ 11,088	$ 9,336
Income from continuing operations	969	931	856	467	325
Net income	3,046	1,753	1,582	2,946	2,568
Per Share Data					
Basic:					
Income from continuing operations	$1.42	$1.32	$1.21	$0.66	$0.46
Net income	$4.48	$2.49	$2.24	$4.15	$3.62
Diluted:					
Income from continuing operations	$1.42	$1.31	$1.21	$0.65	$0.46
Net income	$4.46	$2.47	$2.23	$4.13	$3.61
Statement of Cash Flows Data[b]					
Additions to property, plant and equipment related to continuing operations	$ 5,160	$ 4,443	$ 4,361	$ 2,767	$ 2,917
Dividends paid	543	508	480	567	704
Dividends per share	$0.80	$0.72	$0.68	$0.80	$0.99
Balance Sheet Data as of December 31:					
Total assets	$ 36,011	$ 35,620	$ 35,306	$ 31,371	$ 50,014
Total long-term debt, including capitalized leases	5,323	6,394	6,512	4,674	7,601

(a) Includes impairments to producing properties of $132 million, $96 million, $371 million, $310 million and $447 million in 2014, 2013, 2012, 2011 and 2010 (see Item 8. Financial Statements and Supplementary Data – Note 14 to the consolidated financial statements). Includes impairments to unproved properties of $306 million, $572 million and $227 million in 2014, 2013 and 2012 (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations).

(b) We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014 (see Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements); and our downstream business was spun-off on June 30, 2011. The applicable periods have been recast to reflect these businesses as discontinued operations.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data and the other financial information found elsewhere in this Form 10-K. The following discussion includes forward-looking statements that involve certain risks and uncertainties. See "Disclosures Regarding Forward-Looking Statements" (immediately prior to Part I) and Item 1A. Risk Factors.

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 crude oil and condensate, NGLs and natural gas in North America;
- International E&P – explores for, produces and markets crude oil and condensate, NGLs 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.

Executive Summary

Marathon Oil delivered against 2014 performance commitments by increasing production by 35 percent in the three core U.S. resource plays. We added 305 mmboe of net proved reserves during the year, of which 296 mmboe were in our North America E&P segment. We executed two strategic dispositions for aggregate cash proceeds of more than $4 billion, closing the sale of our Angola assets in the first quarter and our Norway business in the fourth quarter. We executed share repurchases in the first half of the year worth $1 billion. We ended 2014 with liquidity of $4.9 billion comprised of $2.4 billion of cash and $2.5 billion available through a committed multi-year credit facility. Although commodity prices began a substantial decline in the second half of 2014 which continued into 2015, we believe that we are well positioned to continue to satisfy operational objectives and capital commitments with the cash and cash equivalents on hand, internally generated cash flow from operations and available borrowing capacity.

Significant 2014 operating and financial activities include the following:

- Production from continuing operations, excluding Libya, up 8 percent over last year
- North America E&P net sales volumes averaged 238 mboed, an 18 percent increase over last year
- Production from our U.S. resource plays averaged 181 mboed, a 35 percent increase over last year
    - Eagle Ford averaged net sales volumes of 112 mboed, a 38 percent increase
    - Bakken averaged net sales volumes of 51 mboed, a 31 percent increase
    - Oklahoma Resource Basins averaged net sales volumes of 18 mboed, a 29 percent increase
- Total net proved reserves related to continuing operations increased 6 percent to approximately 2.2 bboe
- Recorded 97 percent average operational availability for our operated assets
- Announced Jisik-1 exploration discovery on the operated Harir Block in the Kurdistan Region of Iraq
- Closed Norway and Angola sales for aggregate cash proceeds of more than $4 billion
- Repurchased 29 million common shares for $1 billion
- Increased quarterly dividend by 11 percent to 21 cents per share in the second quarter
- Increased income from continuing operations per diluted share to $1.42 compared to $1.31 in 2013, by 8 percent

Market Conditions

Prevailing prices for the crude oil and condensate, NGLs, natural gas and synthetic crude oil that we produce significantly impact our revenues and cash flows. Beginning in the second half of 2014, the crude oil benchmark prices began to decline and this decline continued into early 2015. Crude oil benchmark prices are likely to remain volatile based on global supply and demand and could decline further. In addition, the Henry Hub natural gas benchmark began to decline in late 2014 and continued its decline into 2015. Because both WTI crude oil and Brent crude oil benchmark prices were greater than $90 per barrel for the first nine months of 2014, and the Henry Hub natural gas price decline began in late 2014, the magnitude of these commodity declines is not fully evident in the tables below that report 2014 annual price realizations averages relative to our operating segments. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Critical Accounting Estimates for further discussion of how a substantial extended decline in commodity price changes could impact us.

North America E&P

The following table presents our average price realizations and the related benchmarks for crude oil, NGLs and natural gas for 2014, 2013 and 2012:

	2014	2013	2012
Average Price Realizations [(a)]			
Crude Oil and Condensate *(per bbl)*			
Bakken	$81.63	$90.25	$83.11
Eagle Ford	87.99	99.69	100.14
Oklahoma Resource Basins	87.15	94.84	89.26
Other North America [(b)]	84.21	90.42	91.75
Total Crude Oil and Condensate	85.25	94.19	91.30
Natural Gas Liquids *(per bbl)*			
Bakken	$43.25	$41.60	$42.35
Eagle Ford	29.60	30.16	32.96
Oklahoma Resource Basins	32.61	35.28	31.82
Other North America [(b)]	51.12	55.69	52.51
Total Natural Gas Liquids	33.42	35.12	39.57
Total Liquid Hydrocarbons *(per bbl)* [(c)]			
Bakken	$79.41	$87.76	$81.36
Eagle Ford	75.83	84.95	88.09
Oklahoma Resource Basins	50.86	50.77	49.21
Other North America [(b)]	81.88	88.16	89.03
Total Liquid Hydrocarbons	77.02	85.20	85.80
Natural Gas *(per mcf)*			
Bakken	$5.28	$3.90	$3.11
Eagle Ford	4.43	3.67	3.03
Oklahoma Resource Basins	4.49	3.78	3.05
Other North America [(b)]	4.65	3.95	4.20
Total Natural Gas	4.57	3.84	3.92
Benchmarks			
WTI crude oil average of daily prices *(per bbl)*	$92.91	$98.05	$94.15
LLS crude oil average of daily prices *(per bbl)*[(d)]	96.64	107.36	111.71
Mont Belvieu NGLs *(per bbl)* [(e)]	32.52	33.78	38.59
Henry Hub natural gas settlement date average (per *mmbtu)*	4.42	3.65	2.79

(a) Excludes gains or losses on derivative instruments.
(b) Includes Gulf of Mexico and other conventional onshore U.S. production, plus Alaska in 2013 and 2012.
(c) Inclusion of realized gains (losses) on crude oil derivative instruments would have increased (decreased) average liquid hydrocarbon price realizations per barrel by $(0.27) and $0.40 for 2013 and 2012. There were no crude oil derivative instruments for 2014.
(d) Bloomberg Finance LLP: LLS St. James.
(e) Bloomberg Finance LLP: Y-grade Mix NGL of 50% ethane, 25% propane, 10% butane, 5% isobutane and 10% natural gasoline.

Crude oil and condensate – Our crude oil and condensate price realizations may differ from the benchmark due to the quality and location of the product. Crude oil benchmark prices decreased in 2014 compared to 2013. This price decline continued into 2015 with WTI crude oil and LLS crude oil averaging $47.33 and $48.82 per bbl in January 2015.

Natural gas liquids – The majority of our NGL volumes are sold at reference to Mont Belvieu prices. Average Mount Belvieu NGL prices for 2014 were modestly lower than for 2013. Our net NGL sales volumes continue to grow due to development of our U.S. resource plays, increasing 164 percent from 2012 to 2014.

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 natural gas settlement prices were higher in 2014 compared to 2013. Henry Hub natural gas settlement prices averaged $3.19 per mmtbu for January 2015.

International E&P

The following table presents our average price realizations and the related benchmark for crude oil for 2014, 2013 and 2012:

	2014	2013	2012
Average Price Realizations			
Crude Oil and Condensate *(per bbl)*			
Equatorial Guinea	$81.01	$90.62	$92.56
United Kingdom	94.31	110.76	109.50
Libya	94.70	122.92	127.31
Total Crude Oil and Condensate	87.23	108.18	113.61
Natural Gas Liquids *(per bbl)*			
Equatorial Guinea[(a)]	$1.00	$1.00	$1.00
United Kingdom[(b)]	67.73	72.14	78.81
Total Natural Gas Liquids	2.46	5.24	8.32
Total Liquid Hydrocarbons *(per bbl)*			
Equatorial Guinea	$54.29	$60.34	$64.33
United Kingdom	93.75	108.92	107.31
Libya	94.70	122.92	127.31
Total Liquid Hydrocarbons	68.98	91.04	100.02
Natural Gas *(per mcf)*			
Equatorial Guinea[(a)]	$0.24	$0.24	$0.24
United Kingdom	8.27	10.64	9.72
Libya	3.11	5.44	5.76
Total Natural Gas	0.72	1.15	1.33
Benchmark			
Brent (Europe) crude oil *(per bbl)*[(c)]	$99.02	$108.64	$111.65

(a) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, Atlantic Methanol Production Company LLC and Equatorial Guinea LNG Holdings Limited, which are equity method investees. We include our share of income from each of these equity method investees in our International E&P segment.

(b) Related sales volumes one mbbld or less for all periods presented.

(c) Average of monthly prices obtained from EIA website.

Crude oil and condensate – Our international crude oil and condensate production is generally sold in relation to the Brent crude oil benchmark. Crude oil benchmark prices decreased in 2014 compared to 2013. This price decline continued into 2015 with Brent crude oil averaging $47.86 per bbl in January 2015.

Natural gas liquids and *natural gas* – Our NGL and natural gas sales from E.G. are subject to fixed-price, term contracts, making realized prices in this area less volatile; therefore, our reported average natural gas realized prices for the International E&P segment will not fully track market price movements. Although natural gas prices in Europe tend to be considerably higher than in the U.S., these prices decreased in 2014 compared to 2013.

Oil Sands Mining

The Oil Sands Mining segment produces and sells various qualities of synthetic crude oil. Output mix can be impacted by operational reliability or planned unit outages at the mines or upgrader. Sales prices for roughly two-thirds of the normal output mix have historically tracked movements in the WTI crude oil benchmark and one-third have historically tracked movements in the Canadian heavy crude oil benchmark, primarily WCS. Comparing 2014 and 2013, the WCS crude oil discount to WTI crude oil narrowed by $5.97 per barrel. A comparison of 2014 compared to 2013 indicate the WTI crude oil benchmark decreased while the WCS crude oil benchmark slightly increased. However, both WTI and WCS crude oil benchmarks declined in January 2015 with prices averaging $47.33 per bbl and $30.43 per bbl, respectively.

The operating cost structure of our Oil Sands Mining operations is predominantly fixed and therefore many of the costs incurred in times of full operation continue during production downtime. Per-unit costs are sensitive to production rates. Key variable costs are natural gas and diesel fuel, which track commodity markets such as the Canadian Alberta Energy Company ("AECO") natural gas sales index and crude oil prices. As average price realizations are typically at a discount to WTI and the operating cost structure for Oil Sands Mining is predominately fixed, sustained declines in oil prices could result in operating losses.

The following table presents our average price realizations and the related benchmarks that impacted both our revenues and variable costs for 2014, 2013 and 2012:

	2014	2013	2012
Average Price Realizations			
Synthetic Crude Oil *(per bbl)*	$83.35	$87.51	$81.72
Benchmark			
WTI crude oil *(per bbl)*	$92.91	$98.05	$94.15
WCS crude oil *(per bbl)*[a]	$73.60	$72.77	$73.18
AECO natural gas sales index *(per mmbtu)*[b]	$3.99	$3.08	$2.39

(a) Average of monthly prices based upon average WTI adjusted for differentials unique to western Canada.
(b) Monthly average AECO day ahead index.

Net Sales Volumes

Our net sales volumes from continuing operations averaged 415 mboed, 404 mboed and 389 mboed for 2014, 2013 and 2012. As liftings from Libya were sporadic during this 3-year period, a more representative comparison is net sales volumes from continuing operations excluding Libya, which was 408 mboed, 376 mboed and 344 mboed for 2014, 2013 and 2012. The continued ramp up of production from our U.S. resource plays has been the most significant contributor to the increases when comparing results excluding Libya, partially offset by decreases from domestic asset sales and normal production declines. Net sales volumes related to the Angola and Norway discontinued operations averaged 54 mboed, 89 mboed and 90 mboed for 2014, 2013 and 2012, representing 12 percent, 18 percent and 19 percent of total company net sales volumes in those periods.

The following table presents North America E&P segment net sales volumes by product and geographic area for 2014, 2013 and 2012:

	Year Ended December 31,		
Net Sales Volumes	2014	2013	2012
North America E&P			
Crude Oil and Condensate *(mbbld)*			
Bakken	45	35	27
Eagle Ford	72	51	23
Oklahoma Resource Basins	3	2	1
Other North America[(a)]	37	38	45
Total Crude Oil and Condensate	157	126	96
Natural Gas Liquids *(mbbld)*			
Bakken	3	2	1
Eagle Ford	19	14	5
Oklahoma Resource Basins	5	4	2
Other North America[(a)]	2	3	3
Total Natural Gas Liquids	29	23	11
Total Liquid Hydrocarbons *(mbbld)*			
Bakken	48	37	28
Eagle Ford	91	65	28
Oklahoma Resource Basins	8	6	3
Other North America[(a)]	39	41	48
Total Liquid Hydrocarbons	186	149	107
Natural Gas *(mmcfd)*			
Bakken	18	13	8
Eagle Ford	123	94	37
Oklahoma Resource Basins	61	48	32
Other North America[(a)]	108	157	281
Total Natural Gas	310	312	358
Equivalent Barrels *(mboed)*			
Bakken	51	39	29
Eagle Ford	112	81	34
Oklahoma Resource Basins	18	14	8
Other North America[(a)]	57	67	95
Total North America E&P *(mboed)*	238	201	166

(a) Includes Gulf of Mexico and other conventional onshore U.S. production, plus Alaska in 2013 and 2012.

North America E&P segment average net sales volumes in 2014 increased 18 percent when compared to 2013. Net liquid hydrocarbon sales volumes increased 37 mbbld in 2014 primarily reflecting continued growth from our three core U.S. resource plays and net natural gas sales volumes decreased 2 mmcfd in 2014 primarily due to the shut-in and exit from Powder River Basin operations and the January 2013 sale of our Alaska assets, partially offset by the increases from the U.S. resource plays.

North America E&P segment average net sales volumes in 2013 increased 21 percent when compared to 2012, primarily due to higher liquid hydrocarbon net sales volumes resulting from ongoing development programs in our three key U.S. resource plays, partially offset by lower natural gas sales volumes, primarily the result of the January 2013 sale of our Alaska assets.

Refer to the Item 1. Business section for additional detail related to net sales volumes by asset.

The following table presents International E&P and OSM segments net sales volumes by product and geographic area for 2014, 2013 and 2012:

	Year Ended December 31,		
Net Sales Volumes	2014	2013	2012
International E&P			
Crude Oil and Condensate *(mbbld)*			
Equatorial Guinea	21	23	25
United Kingdom	11	14	15
Libya	7	24	42
Total Crude Oil and Condensate	39	61	82
Natural Gas Liquids *(mbbld)*			
Equatorial Guinea	10	11	11
United Kingdom	—	1	1
Total Natural Gas Liquids	10	12	12
Total Liquid Hydrocarbons *(mbbld)*			
Equatorial Guinea	31	34	36
United Kingdom	11	15	16
Libya	7	24	42
Total Liquid Hydrocarbons	49	73	94
Natural Gas *(mmcfd)*			
Equatorial Guinea	439	442	428
United Kingdom[(b)]	28	32	48
Libya	1	22	15
Total Natural Gas	468	496	491
Equivalent Barrels *(mboed)*			
Equatorial Guinea	104	107	107
United Kingdom[(b)]	16	20	24
Libya	7	28	45
Total International E&P *(mboed)*	127	155	176
Oil Sands Mining			
Synthetic Crude Oil *(mbbld)*[(c)]	50	48	47
Total Continuing Operations *(mboed)*	415	404	389
Discontinued Operations - Angola *(mboed)*[(d)]	2	10	—
Discontinued Operations - Norway *(mboed)*[(d)]	52	79	90
Total Company *(mboed)*	469	493	479
Net Sales Volumes of Equity Method Investees			
LNG *(mtd)*	6,535	6,548	6,290
Methanol *(mtd)*	1,092	1,249	1,298

(b) Includes natural gas acquired for injection and subsequent resale of 6 mmcfd, 7 mmcfd and 15 mmcfd for 2014, 2013, and 2012.

(c) Includes blendstocks.

(d) As we closed the sale of our Angola assets and our Norway business during 2014, they are reflected as discontinued operations and excluded from segments in all periods presented.

International E&P segment average net sales volumes in 2014 decreased 18 percent when compared to 2013. We had lower oil sales from Libya in 2014 as a result of third party labor strikes at the Es Sider terminal and ongoing civil unrest. Excluding Libya, net sales volumes decreased 6 percent in 2014 compared to 2013, primarily due to reliability issues and production decline in the U.K. and lower reliability at the non-operated methanol facility in E.G.

International E&P segment average net sales volumes in 2013 decreased 12 percent when compared to 2012 primarily due to lower liquid hydrocarbon net sales volumes in Libya. Excluding Libya, net sales volumes only decreased 3 percent in 2013 when compared to 2012.

Refer to the Item 1. Business section for additional detail related to net sales volumes by asset.

Oil Sands Mining

Our OSM operations consist of a 20 percent non-operated working interest in the AOSP. Our net synthetic crude oil sales volumes were 50 mbbld in 2014 compared to 48 mbbld in 2013 and 47 mbbld in 2012.

Consolidated Results of Operations: 2014 compared to 2013

Consolidated income from continuing operations after income taxes in 2014 was 4 percent higher than 2013 primarily due to increased net sales volumes in the North America E&P segment which were partially offset by lower average price realizations in all segments, as well as lower net sales volumes in the International E&P segment primarily as a result of civil unrest in Libya.

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

(In millions)	Year Ended December 31, 2014	2013
Sales and other operating revenues, including related party		
North America E&P	$ 5,770	$ 5,068
International E&P	1,410	2,654
Oil Sands Mining	1,556	1,576
Segment sales and other operating revenues, including related party	8,736	9,298
Unrealized loss on crude oil derivative instruments	—	(52)
Sales and other operating revenues, including related party	$ 8,736	$ 9,246

North America E&P sales and other operating revenues increased $702 million from 2013 to 2014 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 average crude oil price realizations.

The following table displays changes in North America E&P segment sales and other operating revenues by product. Refer to the preceding Market Conditions and Net Sales Volumes sections for additional detail related to average price realizations and net sales.

(In millions)	Year Ended December 31, 2013	Increase (Decrease) Related to Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Year Ended December 31, 2014
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 4,638	$ (557)	$ 1,159	$ 5,240
Natural gas	437	82	(3)	516
Realized loss on crude oil derivative instruments	(15)	15		—
Other sales	8			14
Total	$ 5,068			$ 5,770

International E&P sales and other operating revenues decreased $1,244 million in 2014 from the prior year. This decrease was primarily due to lower liquid hydrocarbon net sales volumes in Libya as a result of civil unrest and lower average price realizations in every location.

The following table displays changes in International E&P segment sales and other operating revenues by product. Refer to the preceding Market Conditions and Net Sales Volumes sections for additional detail related to average price realizations and net sales.

(In millions)	Year Ended December 31, 2013	Increase (Decrease) Related to Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Year Ended December 31, 2014
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 2,398	$ (397)	$ (761)	$ 1,240
Natural gas	209	(74)	(11)	124
Other sales	47			46
Total	$ 2,654			$ 1,410

Oil Sands Mining sales and other operating revenues decreased $20 million in 2014 from 2013. This decrease was primarily due to lower average price realizations compared to 2013, partially offset by increased net sales volumes in 2014.

The following table displays changes in OSM segment sales of synthetic crude oil and other operating revenues. Refer to the preceding Market Conditions and Net Sales Volumes sections for additional detail related to average price realizations and net sales.

(In millions)	Year Ended December 31, 2013	Increase (Decrease) Related to Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Year Ended December 31, 2014
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$ 1,542	$ (76)	$ 59	$ 1,525
Other sales	34			31
Total	$ 1,576			$ 1,556

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 expired December 2013, had no impact in 2014 compared to a net unrealized loss of $52 million in 2013. See Item 8. Financial Statements and Supplementary Data - Note 15 to the consolidated financial statements for information about our derivative positions.

Marketing revenues increased $31 million in 2014 from 2013. The increase in 2014 is primarily due to higher marketing activity levels in both the North America E&P and OSM segments. Marketing activities include the purchase of commodities from third parties for resale, or in order to meet sales contracts, and serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points. Because the volume of marketing activity is based on market dynamics, it can fluctuate from period to period.

Net loss on disposal of assets in 2014 primarily includes the pretax loss on the sale of non-core acreage located in the far northwest portion of the Williston Basin. The net loss on disposal of assets in 2013 primarily included pretax losses on the sale of our DJ Basin interests and the conveyance of our Marcellus interests to the operator, offset by pretax gains on the sales of the Neptune gas plant and our remaining assets in Alaska. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

Production expenses increased $90 million in 2014 from 2013 primarily related to increased North America E&P net sales volumes in the Eagle Ford and Bakken. The production expense rate (expense per boe) decreased in North America E&P in 2014 compared to 2013 primarily due to improved operating efficiencies in the Eagle Ford. The expense per boe increased in the International E&P segment due to a subsea power project at our non-operated Foinaven field as well as a turnaround in Brae in the U.K. and a non-recurring riser repair in E.G.

The following table provides production expense rates for each segment:

($ per boe)	2014	2013
North America E&P	$10.25	$10.86
International E&P	$8.31	$6.36
Oil Sands Mining [(a)]	$44.53	$46.30

(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.

Other operating expenses increased $73 million in 2014 from the prior year, primarily due to increased shipping and handling costs in North America in line with increased sales volumes, as well as the impact of a settlement related to the calculation of the net profits interest payments associated with our Alba Plant equity interests in E.G.

Marketing expenses increased $29 million in 2014 from the prior year, consistent with the increase in marketing revenues discussed above.

Exploration expenses decreased $98 million in 2014 from 2013, primarily related to our North America E&P segment as a result of larger non-cash unproved property impairments during 2013 related to Eagle Ford leases that either expired or that we did not expect to drill. These decreases were partially offset by increases in 2014 expenses related to the operated Key Largo, the outside-operated Perseus, the outside-operated second Shenandoah appraisal well in the Gulf of Mexico and our operated Sodalita West #1 exploratory well in E.G.

The following table summarizes the components of exploration expenses:

	Year Ended December 31,	
(In millions)	2014	2013
Unproved property impairments	$ 306	$ 572
Dry well costs	317	148
Geological and geophysical	85	80
Other	85	91
Total exploration expenses	$ 793	$ 891

Depreciation, depletion and amortization increased $361 million in 2014 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 expense in 2014 is primarily due to higher North America E&P sales volumes as a result of ongoing development programs over our three U.S. resource plays.

The DD&A rate, which is impacted by changes in reserves, capitalized costs and sales volume mix by field, can also cause changes to our DD&A. The following table provides DD&A rates for each segment:

($ per boe)	2014	2013
North America E&P	$26.95	$26.23
International E&P	$5.79	$5.86
Oil Sands Mining	$12.07	$12.39

Impairments in 2014 included certain Gulf of Mexico properties. Impairments in 2013 primarily related to a second LNG production train in E.G., the Ozona development in the Gulf of Mexico, and our Powder River Basin asset in Wyoming. See Item 8. Financial Statements and Supplementary Data - Note 14 to the consolidated financial statements for information about these impairments.

Taxes other than income include production, severance and ad valorem taxes in the U.S., which tend to increase or decrease in relation to sales volumes and revenues, and increased $61 million in 2014 from 2013, consistent with similar increases in the North America E&P segment.

	Year Ended December 31,	
(In millions)	2014	2013
Production and severance	$ 240	$ 202
Ad valorem	74	61
Other	92	82
Total	$ 406	$ 345

Net interest and other decreased $40 million in 2014 from 2013 primarily due to an increase in capitalized interest and higher net foreign currency gains as well as a dividend received in 2014 from a mutual insurance company of which we are an owner. See Item 8. Financial Statements and Supplementary Data - Note 8 to the consolidated financial statements for more detailed information.

Provision for income taxes decreased $1,070 million in 2014 from 2013 primarily due to the decrease in pretax income from higher tax jurisdictions, primarily Libya. The following is an analysis of the effective tax rates for 2014 and 2013.

	2014	2013
Statutory rate applied to income from continuing operations before income taxes	35%	35%
Effects of foreign operations, including foreign tax credits	(6)	26
Change in permanent reinvestment assertion	(19)	—
Adjustments to valuation allowances	21	(1)
Other	(2)	1
Effective income tax rate on continuing operations	29%	61%

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. 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 2014 as compared to 2013 due to a shift in pretax income mix between high and low tax jurisdictions. This is primarily related to decreased sales in Libya where the tax rate is in excess of 90 percent. Excluding Libya, the effective tax rates on continuing operations for 2014 and 2013 would be 27 percent and 38 percent.

Change in permanent reinvestment assertion – In the second quarter of 2014, we reviewed our foreign operations, including the disposition of our Norway business, and concluded that our foreign operations do not have the same level of immediate capital needs as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings associated with our U.K. operations to be permanently reinvested outside the U.S. The U.K. statutory tax rate is in excess of the U.S. statutory tax rate, and therefore, foreign tax credits associated with these earnings exceeds any incremental U.S. tax liabilities.

Adjustments to valuation allowances **–** In 2014, we increased the valuation allowance against foreign tax credits as a result of removing the permanent reinvestment assertion on our U.K. operations since the U.K. statutory tax rate is in excess of the U.S. statutory tax rate. In 2013, valuation allowances decreased primarily due to the disposal of our Indonesian assets.

See Item 8. Financial Statements and Supplementary Data - Note 9 to the consolidated financial statements for further information about income taxes.

Discontinued operations is presented net of tax. We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014, and both are reflected as discontinued operations and excluded from the International E&P segment in all periods presented. Included in discontinued operations for 2014 are after-tax gains of $532 million and $976 million related to the dispositions of Angola and Norway, respectively. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements.

Average net sales volumes from Norway were 52 mboed and 79 mboed in 2014 and 2013. Sales volumes decreased in 2014 compared to 2013 primarily as the result of water breakthrough, as anticipated at Volund, as well as natural decline in the remaining fields. Alvheim sales were also impacted in 2014 by severe winter weather during the first quarter which resulted in eight days of curtailed production and again during the third quarter due to planned maintenance and system upgrades on the Alvheim FPSO. In addition, 2014 Norway sales volumes are only reported through the October 15, 2014 close date.

Segment Results: 2014 compared to 2013

Segment income for 2014 and 2013 is summarized and reconciled to net income in the following table.

	Year Ended December 31,	
(In millions)	2014	2013
North America E&P	$ 693	$ 529
International E&P	568	758
Oil Sands Mining	235	206
Segment income	1,496	1,493
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(399)	(470)
Unrealized loss on crude oil derivative instruments	—	(33)
Net loss on dispositions	(58)	(20)
Impairments	(70)	(39)
Income from continuing operations	969	931
Discontinued operations	2,077	822
Net income	$ 3,046	$ 1,753

North America E&P segment income increased $164 million in 2014 compared to 2013. The increase was largely due to increased liquid hydrocarbon net sales volumes primarily in the Eagle Ford, Bakken and Oklahoma Resource Basins and lower exploration expenses, partially offset by lower average price realizations.

International E&P segment income decreased $190 million in 2014 compared to 2013. The decrease was primarily due to lower liquid hydrocarbon net sales volumes and lower average price realizations partially offset by a decrease in the taxes related to Libya, a high tax jurisdiction. Also, other operating expenses were higher in 2014 primarily due to the impact of a settlement related to the calculation of the net profits interest payments associated with our Alba Plant equity interests in E.G.

Oil Sands Mining segment income increased $29 million in 2014 compared to 2013. This increase was primarily a result of higher operating expenses in 2013 related to a turnaround.

Consolidated Results of Operations: 2013 compared to 2012

Consolidated income from continuing operations after income taxes in 2013 was 9 percent higher than 2012 primarily due to higher net sales volumes in the North America E&P segment, partially offset by higher exploration expenses and lower net sales volumes as well as lower average price realizations in the International E&P segment.

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

(In millions)	Year Ended December 31, 2013	2012
Sales and other operating revenues, including related party		
North America E&P	$ 5,068	$ 3,944
International E&P	2,654	3,719
Oil Sands Mining	1,576	1,521
Segment sales and other operating revenues, including related party	9,298	9,184
Unrealized gain (loss) on crude oil derivative instruments	(52)	53
Sales and other operating revenues, including related party	$ 9,246	$ 9,237

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 displays changes in North America E&P segment sales and other operating revenues by product. Refer to the preceding Market Conditions and Sales sections for additional detail related to average price realizations and net sales.

(In millions)	Year Ended December 31, 2012	Increase (Decrease) Related to Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Year Ended December 31, 2013
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 3,352	$ (33)	$ 1,319	$ 4,638
Natural gas	513	(9)	(67)	437
Realized gain on crude oil derivative instruments	17	(17)		(15)
Other sales	62			8
Total	$ 3,944			$ 5,068

International E&P sales and other operating revenues decreased $1,065 million in 2013 from the prior year. This decrease was primarily due to lower liquid hydrocarbon net sales volumes in Libya and lower liquid hydrocarbon average price realizations.

The following table displays changes in International E&P segment sales and other operating revenues by product. Refer to the preceding Market Conditions and Sales sections for additional detail related to average price realizations and net sales.

(In millions)	Year Ended December 31, 2012	Increase (Decrease) Related to Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Year Ended December 31, 2013
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 3,433	$ (237)	$ (798)	$ 2,398
Natural gas	240	(33)	2	209
Other sales	46			47
Total	$ 3,719			$ 2,654

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 higher average price realizations when compared to 2012. The increase was partially offset by lower feedstock sales in 2013.

The following table displays changes in OSM segment sales of synthetic crude oil and other operating revenues. Refer to the preceding Market Conditions and Sales sections for additional detail related to average price realizations and net sales.

(In millions)	Year Ended December 31, 2012	Increase (Decrease) Related to: Price Realizations	Increase (Decrease) Related to: Net Sales Volumes	Year Ended December 31, 2013
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$ 1,409	$ 102	$ 31	$ 1,542
Other sales	112			34
Total	$ 1,521			$ 1,576

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 expired 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 15 to the consolidated financial statements for information about our derivative positions.

Marketing revenues decreased $650 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 pretax losses on the sale of our DJ Basin interests and the conveyance of our Marcellus interests to the operator offset by pretax gains on the sales of the Neptune gas plant and our remaining assets in Alaska. The net gain on disposal of assets in 2012 consisted primarily of a pretax gain on the sale of our interests in several Gulf of Mexico crude oil pipeline systems partially offset by a pretax loss related to our exit from Indonesia. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for further details about these dispositions.

Production expenses increased $77 million in 2013 from 2012 primarily related to increased North America E&P net sales volumes in the Eagle Ford and Bakken, partially offset by decreased International E&P net sales volumes. 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 production expense rate (expense per boe) increase in International E&P in 2013 compared to 2012 was primarily due to maintenance and workovers performed in Libya while production was down as a result of third-party labor strikes at the Es Sider terminal during the second half of 2013.

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

($ per boe)	2013	2012
North America E&P	$10.86	$11.59
International E&P	$6.36	$5.85
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 $658 million in 2013 from the prior year, consistent with the decreases in marketing revenues discussed above.

Exploration expenses were $206 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 dry well costs and geological and geophysical costs. Unproved property impairments in 2012 related to Marcellus, Eagle Ford, and Indonesia.

	Year Ended December 31,	
(In millions)	2013	2012
Unproved property impairments	$ 572	$ 227
Dry well costs	148	230
Geological and geophysical	80	127
Other	91	101
Total exploration expenses	$ 891	$ 685

Depreciation, depletion and amortization increased $492 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, partially offset by the disposition of our Alaska assets in January 2013. See Item 8. Financial Statements and Supplementary Data - Note 5 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, capitalized costs and sales volume mix by field, 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 higher 2013 DD&A rate in International E&P versus 2012 is due to an increase in estimated abandonment costs in the U.K.

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	$5.86	$4.96
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 14 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 $102 million in 2013 from 2012. With the increase in North America E&P revenues and net sales volumes, production and severance taxes increased $76 million in 2013 from 2012. In addition, ad valorem taxes were slightly higher because the value of our North America E&P assets has increased with continued acquisitions in the Eagle Ford.

	Year Ended December 31,	
(In millions)	2013	2012
Production and severance	$ 202	$ 126
Ad valorem	61	57
Other	82	60
Total	$ 345	$ 243

Net interest and other increased $56 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 8 to the consolidated financial statements for more detailed information.

Provision for income taxes decreased $786 million in 2013 from 2012 primarily due to the decrease in pretax income from continuing operations, primarily in Libya, which is a higher tax jurisdiction. The following is an analysis of the effective income 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	26	36
Adjustments to valuation allowances	(1)	—
Other	1	1
Effective income tax rate on continuing operations	61%	72%

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 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. Excluding Libya, the effective tax rates on continuing operations for 2013 and 2012 would be 38 percent and 37 percent.

See Item 8. Financial Statements and Supplementary Data - Note 9 to the consolidated financial statements for further information about income taxes.

Discontinued operations is presented net of tax. In 2014, we closed the sales of our Angola assets and Norway business; therefore, the Angola and Norway operations are reflected as discontinued operations in all periods presented. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements.

Average net sales volumes from Norway were 79 mboed and 90 mboed in 2013 and 2012. Sales volumes decreased in 2013 compared to 2012 primarily as the result of well workovers in 2013 as well as natural decline in the remaining fields.

Segment Results: 2013 compared to 2012

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

	Year Ended December 31,	
(In millions)	2013	2012
North America E&P	$ 529	$ 382
International E&P	758	895
Oil Sands Mining	206	171
Segment income	1,493	1,448
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(470)	(467)
Unrealized gain (loss) on crude oil derivative instruments	(33)	34
Net gain (loss) on dispositions	(20)	72
Impairments	(39)	(231)
Income from continuing operations	931	856
Discontinued operations	822	726
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 in 2013 was also negatively impacted by the previously discussed higher exploration expenses related to non-cash unproved property impairments and the sale of our Alaska assets.

International E&P segment income decreased $137 million in 2013 compared to 2012. The decrease was primarily related to the lower liquid hydrocarbon net sales volumes in Libya and lower average liquid hydrocarbon price realizations, partially offset by lower taxes as a result of decreased pretax income from Libya which is a higher tax jurisdiction.

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

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

Cash Flows

The following table presents sources and uses of cash and cash equivalents for 2014, 2013 and 2012:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Sources of cash and cash equivalents			
Continuing operations	$ 4,736	$ 4,388	$ 2,874
Discontinued operations	751	882	1,143
Disposals of assets	3,760	450	467
Borrowings including commercial paper, net	—	—	2,197
Other	214	189	129
Total sources of cash and cash equivalents	$ 9,461	$ 5,909	$ 6,810
Uses of cash and cash equivalents			
Acquisitions	$ (21)	$ (74)	$ (1,033)
Additions to property, plant and equipment	(5,160)	(4,443)	(4,361)
Investing activities of discontinued operations	(376)	(550)	(579)
Purchases of common stock	(1,000)	(500)	—
Commercial paper, net	(135)	(65)	—
Debt repayments	(68)	(182)	(145)
Dividends paid	(543)	(508)	(480)
Other	(24)	(7)	(21)
Total uses of cash and cash equivalents	$ (7,327)	$ (6,329)	$ (6,619)

While the 2014 commodity benchmark prices were relatively strong for most of the year, beginning in the second half of 2014 these benchmarks began to decline and continued to decline during the early portion of 2015 and remain volatile based on global supply and demand. While we are unable to predict future commodity price movements, if this lower price trend continues, it would negatively impact our cash flows from operating activities.

Cash flows from continuing operations in 2014 were higher than in 2013 due to increased net sales volumes in the North America E&P segment and lower cash tax payments (primarily Libya, a higher tax jurisdiction), partially offset by lower average price realizations in all segments, as well as lower net sales volumes in the International E&P segment. The increase in cash flows from continuing operations in 2013 primarily reflects the increase in North America E&P liquid hydrocarbon net sales volumes on operating income.

Disposals of assets in 2014 primarily reflect the $2 billion aggregate proceeds from the sale of our Angola assets in the first quarter and $2.1 billion proceeds from the sale of our Norway business in the fourth quarter. 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. Disposition transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements.

Additions to property, plant and equipment are our most significant use of cash and cash equivalents. The following table shows capital expenditures related to continuing operations by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows for 2014, 2013 and 2012:

	Year Ended December 31,		
(In millions)	2014	2013	2012
North America E&P	$ 4,698	$ 3,649	$ 3,988
International E&P	534	456	235
Oil Sands Mining	212	286	188
Corporate	51	58	115
Total capital expenditures	5,495	4,449	4,526
Change in capital expenditure accrual	(335)	(6)	(165)
Additions to property, plant and equipment	$ 5,160	$ 4,443	$ 4,361

As of December 31, 2014, we had repurchased a total of 121 million common shares at a cost of $4.7 billion, including 29 million shares at a cost of $1 billion in the first six months of 2014 and 14 million shares at a cost of $500 million in the third quarter of 2013.

See Item 8. Financial Statements and Supplementary Data – Note 22 to the consolidated financial statements for discussion of purchases of common stock.

Liquidity and Capital Resources

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, continued access to capital markets, 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. 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 and other amounts that may ultimately be paid in connection with contingencies.

At December 31, 2014, we had approximately $4.9 billion of liquidity consisting of $2.4 billion in cash and cash equivalents and $2.5 billion availability under our revolving credit facility. As discussed in more detail below in “Outlook”, we are targeting a $3.5 billion Budget for 2015. Based on our projected 2015 cash outlays for our capital program and dividends, we expect to outspend our cash flows from operations for the year. We will be constantly monitoring our available liquidity during 2015 and we have the flexibility to adjust our Budget throughout the year in response to the commodity price environment. We will also continue to drive the fundamentals of expense management, including organizational capacity and operational reliability.

Capital Resources

Credit Arrangements and Borrowings

In May 2014, we amended our $2.5 billion unsecured revolving credit facility and extended the maturity to May 2019. See Note 16 to the consolidated financial statements for additional terms and rates. At December 31, 2014, we had no borrowings against our revolving credit facility and no amounts outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

At December 31, 2014, we had $6,391 million in long-term debt outstanding, and $1,068 million is due within one year, of which the majority is due in the fourth quarter of 2015. 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.

Shelf Registration

We have a universal shelf registration statement filed with the SEC, under which we, as "well-known seasoned issuer" for purposes of SEC rules, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities from time to time.

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 16 percent at December 31, 2014 and 25 percent at December 31, 2013.

(Dollars in millions)	2014	2013
Commercial paper	$ —	$ 135
Long-term debt due within one year	1,068	68
Long-term debt	5,323	6,394
Total debt	$ 6,391	$ 6,597
Cash	$ 2,398	$ 264
Equity	$ 21,020	$ 19,344
Calculation		
Total debt	$ 6,391	$ 6,597
Minus cash	2,398	264
Total debt minus cash	3,993	6,333
Total debt	6,391	6,597
Plus equity	21,020	19,344
Minus cash	2,398	264
Total debt plus equity minus cash	$ 25,013	$ 25,677
Cash-adjusted debt-to-capital ratio	16%	25%

Capital Requirements

Capital Spending

Our approved Budget for 2015 is $3.5 billion. Additional details are discussed below in "Outlook."

Share Repurchase Program

The remaining share repurchase authorization as of December 31, 2014 is $1.5 billion.

Other Expected Cash Outflows

As of December 31, 2014, $1,068 million of our long-term debt is due in the next twelve months, most of which is due in the fourth quarter of 2015. Dividends of $543 million were paid during 2014 reflecting quarterly dividends of $0.19 per share in the first two quarters of the year and $0.21 per share in the last two quarters. On January 28, 2015, we announced that our Board of Directors had declared a dividend of $0.21 cents per share on Marathon Oil common stock, payable March 10, 2015, to stockholders of record at the close of business on February 18, 2015.

We plan to make contributions of up to $95 million to our funded pension plans during 2015. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $11 million and $19 million in 2015.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2014.

(In millions)	Total	2015	2016-2017	2018-2019	Later Years
Short and long-term debt (includes interest)[(a)]	$ 10,102	$ 1,363	$ 1,272	$ 1,508	$ 5,959
Lease obligations	200	41	61	50	48
Purchase obligations:					
Oil and gas activities[(b)]	783	442	218	74	49
Service and materials contracts[(c)]	1,077	166	199	89	623
Transportation and related contracts	1,933	222	475	434	802
Drilling rigs and fracturing crews[(d)]	629	422	207	—	—
Other	192	50	29	30	83
Total purchase obligations	4,614	1,302	1,128	627	1,557
Other long-term liabilities reported in the consolidated balance sheet[(e)]	943	133	156	214	440
Total contractual cash obligations[(f)]	$ 15,859	$ 2,839	$ 2,617	$ 2,399	$ 8,004

(a) Includes anticipated cash payments for interest of $295 million for 2015, $590 million for 2016-2017, $426 million for 2018-2019 and $2,422 million for the remaining years for a total of $3,733 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, 2014 our minimum commitment would be $459 million.

(e) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2024. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

(f) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1,958 million. See Item 8. Financial Statements and Supplementary Data – Note 17 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, 2014, 2013 and 2012 aggregated $101 million, $119 million, and $139 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 Budget of $3.5 billion for 2015, including capital expenditures of $3.4 billion. With the continued uncertainty in commodity pricing, we have taken decisive action to protect our optionality and position us to be a stronger E&P company in the long term. Our exploration spending has been reduced by more than 50 percent while we continue to focus on our three U.S. resource plays. We are also prepared to exercise further flexibility in our spend levels as pricing and the macro environment warrant. Our Budget is broken down by reportable segment in the table below.

(In millions)	2015 Budget	Percent of Total
North America E&P	$ 2,885	82%
International E&P	536	15%
Oil Sands Mining [(a)]	21	1%
Segment total	3,442	98%
Corporate and other	79	2%
Total capital, investment and exploration spending budget	$ 3,521	100%

[(a)] Represents the net budget after factoring in reimbursements from the Canadian Federal and Provincial government related to the QUEST CCS project.

North America E&P – Approximately $2.4 billion of our Budget is allocated to our three core U.S. resource plays. More than $1.4 billion is earmarked for the Eagle Ford, where rig count is expected to drop from 18 in late 2014 to 10 by the end of the second quarter of 2015. Included in Eagle Ford spending is approximately $1 billion for drilling and completions. We plan to spend $760 million in the Bakken in North Dakota. Drilling activity will be reduced to two rigs by the end of the first quarter of 2015, down from seven rigs at the end of 2014. Bakken spending includes approximately $550 million for drilling, completions and recompletions. Spending of $226 million is targeted for the Oklahoma Resource Basins, which will also be down to two rigs by the end of the first quarter of 2015. This includes spending of approximately $200 million for drilling and completions.

International E&P – We plan to spend approximately $429 million on our international assets, primarily in E.G., the U.K. and the Kurdistan Region of Iraq.

Approximately $232 million will be spent on a targeted exploration program impacting both the North America E&P and the International E&P segments. The program includes one operated Gulf of Mexico well, participation in a non-operated appraisal well at Shenandoah in the Gulf of Mexico and seismic surveys in Gabon and Ethiopia.

Oil Sands Mining – We expect to spend $95 million for sustaining capital projects in the OSM segment. We hold a 20 percent outside-operated interest in the Athabasca Oil Sands Project.

The remainder of our Budget consists of Corporate and Other and is expected to total approximately $79 million, of which $40 million represents capitalized interest on assets under construction.

For information about expected exploration and development activities more specific to individual assets, see Item 1. Business.

Production Volumes

We forecast 2015 production available for sale from the combined North America E&P and International E&P segments, excluding Libya, to be 370 to 390 net mboed and the OSM segment to be 35 to 45 net mbbld of synthetic crude oil. We expect our U.S. resource plays to achieve production growth of approximately 20 percent in 2015 over 2014. In addition, we expect total production growth, excluding Libya, of 5 to 7 percent year-over-year.

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. In connection with our ongoing portfolio management, future decisions to dispose of assets could result in non-cash impairments in the period such decisions are made.

Personnel

In February 2015, we announced a reduction in workforce impacting approximately 350-400 employees. These reductions focus largely on U.S. payroll employees, weighted toward above-the-field and support services personnel, though we will continue to analyze our staffing needs at all levels and in all locations. Affected employees will be eligible for severance benefits.

Other

Two exploratory wells: Key Largo in the Gulf of Mexico and Sodalita West #1 in E.G. were deemed unsuccessful in early 2015, with well costs incurred through December 31, 2014 charged to dry well expense. In addition, approximately $45 million in costs related to these wells will be charged to dry well expense in the first quarter of 2015.

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.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We strive to comply with all legal requirements regarding the environment, but as 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 crude oil and condensate, NGLs 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. Sustained reduced commodity prices could have a material effect on the quantity and present value of our proved reserves and could also cause us to decrease our near term capital programs and defer investment until prices improved. A shifting of capital expenditures into future periods outside of five years from the initial proved reserve booking could potentially lead to a reduction in proved undeveloped reserves. 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 crude oil and condensate, NGLs, 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 crude oil and condensate, NGLs, 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. However, because we depreciate a majority of our oil and gas properties under the units-of-production method, any reduction in proved reserves could result in an acceleration of future DD&A expense. 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 2014 proved reserves based on 2014 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	$ (1.28)	$ 112	$ 1.42	$ (123)
International E&P	$ (0.28)	$ 13	$ 0.30	$ (14)
Oil Sands Mining	$ (0.63)	$ 9	$ 0.55	$ (8)

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 or income statement, as appropriate. Changes in estimated asset retirement obligations for late life assets could result in future impairment charges. See Item 8. Financial Statements and Supplementary Data – Note 17 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 14 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 crude oil and condensate, NGLs, 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 an 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. The substantial decline in commodity prices during the second half of 2014, and the resulting change in future commodity price assumptions, was a triggering event which required us to reassess long-lived assets related to oil and gas producing properties for impairment as of December 31, 2014. We estimated the fair values using an income approach and concluded that no material impairments were required. See Item 8. Financial Statements and Supplementary Data Note 14 to the consolidated financial statements for discussion of impairments recorded in 2014, 2013 and 2012. Future impairments of long-lived assets are possible if management's current assumptions were to change.

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. After we performed our annual impairment test in April 2014, there was a substantial decline in commodity prices as discussed above. The resulting change in future commodity price assumptions, was a triggering event which required us to reassess our goodwill for impairment as of December 31, 2014. Based on the results of this assessment, we concluded no impairment was required. The calculated fair value of the North America E&P and International E&P reporting units exceeded their respective book values by a significant margin.

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 crude oil and condensate, NGLs, 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 crude oil and condensate, NGLs, natural gas and synthetic crude oil prices and estimates of such future prices are inherently imprecise.
- **Estimated quantities of crude oil and condensate, NGLs, natural gas and synthetic crude oil.** Such quantities are based on a combination of proved and probable reserves such that the combined volumes represent the most likely expectation of recovery.
- **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. A further sustained decline in commodity prices may cause us to reassess our long-lived assets and goodwill for impairment, and could result in future non-cash impairment charges as a result of such impairment assessments.

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 2014, 2013 and 2012, 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 4 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 14 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. In the second quarter of 2014, we reviewed our foreign operations, including the disposition of our Norway business, and concluded that our foreign operations do not have the same level of immediate capital needs as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings associated with our U.K. operations to be permanently reinvested outside the U.S.

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 crude oil and condensate, NGLs, 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 crude oil and condensate, NGLs, 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 3.71 percent for our U.S. pension plans and 4.01 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	$ (35)	$ (4)	$ 37	$ 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 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. 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.

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 19 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

See Item 8. Financial Statements and Supplementary Data – Note 2 to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks related to the volatility of crude oil and condensate, NGL, natural gas and synthetic crude oil prices. 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. 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 14 and 15 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 may 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 business. Our consolidated results for 2013 and 2012 were impacted by crude oil derivatives related to a portion of our North America E&P crude oil sales, all of which expired in December 2013. There were no crude oil derivatives in 2014.

Interest Rate Risk

At December 31, 2014, our portfolio of long-term debt was substantially comprised of fixed rate instruments. We currently manage our exposure to interest rate movements by utilizing interest rate swap agreements that effectively convert a portion of our fixed rate debt to floating interest rate debt. As of December 31, 2014, we had multiple interest rate swap agreements with a total notional of $900 million designated as fair value hedges.

Our sensitivity to interest rate movements and corresponding changes in the fair value of our fixed rate debt portfolio affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices different than 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, 2014, 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]	$ 2
Long-term debt, including amounts due within one year	$ (6,887) [b][c]	$ (216)

[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, 2014, we had no open derivatives related to foreign currency exchange rates.

Counterparty Risk

We are also exposed to financial risk in the event of nonperformance by counterparties. If commodity prices remain at or fall below current levels, some of our counterparties may experience liquidity problems and may not be able to meet their financial obligations to us. We review the creditworthiness of counterparties and use master netting agreements when appropriate.

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). Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. 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.

An evaluation of the design and effectiveness of our internal control over financial reporting, based on the 2013 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, 2014.

The effectiveness of Marathon Oil's internal control over financial reporting as of December 31, 2014 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, 2014, and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework* - 2013 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

Houston, Texas
March 2, 2015

MARATHON OIL CORPORATION
Consolidated Statements of Income

(In millions, except per share data)	Year Ended December 31, 2014	2013	2012
Revenues and other income:			
Sales and other operating revenues, including related party	$ 8,736	$ 9,246	$ 9,237
Marketing revenues	2,110	2,079	2,729
Income from equity method investments	424	423	370
Net gain (loss) on disposal of assets	(90)	(29)	127
Other income	78	64	23
Total revenues and other income	11,258	11,783	12,486
Costs and expenses:			
Production	2,246	2,156	2,079
Marketing, including purchases from related parties	2,105	2,076	2,734
Other operating	462	389	364
Exploration	793	891	685
Depreciation, depletion and amortization	2,861	2,500	2,008
Impairments	132	96	371
Taxes other than income	406	345	243
General and administrative	654	659	676
Total costs and expenses	9,659	9,112	9,160
Income from operations	1,599	2,671	3,326
Net interest and other	(238)	(278)	(222)
Income from continuing operations before income taxes	1,361	2,393	3,104
Provision for income taxes	392	1,462	2,248
Income from continuing operations	969	931	856
Discontinued operations	2,077	822	726
Net income	$ 3,046	$ 1,753	$ 1,582
Per Share Data			
Basic:			
Income from continuing operations	$ 1.42	$ 1.32	$ 1.21
Discontinued operations	$ 3.06	$ 1.17	$ 1.03
Net income	$ 4.48	$ 2.49	$ 2.24
Diluted:			
Income from continuing operations	$ 1.42	$ 1.31	$ 1.21
Discontinued operations	$ 3.04	$ 1.16	$ 1.02
Net income	$ 4.46	$ 2.47	$ 2.23
Dividends	$ 0.80	$ 0.72	$ 0.68
Weighted average shares:			
Basic	680	705	706
Diluted	683	709	710

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

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income

(In millions)	Year Ended December 31, 2014	2013	2012
Net income	$ 3,046	$ 1,753	$ 1,582
Other comprehensive income (loss)			
Postretirement and postemployment plans			
Change in actuarial loss and other	(52)	300	(97)
Income tax benefit (provision)	25	(112)	35
Postretirement and postemployment plans, net of tax	(27)	188	(62)
Derivative hedges			
Net unrecognized gain	1	1	1
Income tax provision	—	—	—
Derivative hedges, net of tax	1	1	1
Foreign currency translation and other			
Unrealized gain (loss)	—	(3)	1
Income tax benefit (provision)	(1)	1	(3)
Foreign currency translation and other, net of tax	(1)	(2)	(2)
Other comprehensive income (loss)	(27)	187	(63)
Comprehensive income	$ 3,019	$ 1,940	$ 1,519

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets

(In millions, except par values and share amounts)	December 31, 2014	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$ 2,398	$ 264
Receivables, less reserve of $3 and $0	1,729	2,134
Inventories	357	364
Other current assets	109	213
Total current assets	4,593	2,975
Equity method investments	1,113	1,201
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $21,884 and $21,895	29,040	28,145
Goodwill	459	499
Other noncurrent assets	806	2,800
Total assets	$ 36,011	$ 35,620
Liabilities		
Current liabilities:		
Commercial paper	$ —	$ 135
Accounts payable	2,545	2,206
Payroll and benefits payable	191	240
Accrued taxes	285	1,445
Other current liabilities	290	239
Long-term debt due within one year	1,068	68
Total current liabilities	4,379	4,333
Long-term debt	5,323	6,394
Deferred tax liabilities	2,486	2,492
Defined benefit postretirement plan obligations	598	604
Asset retirement obligations	1,917	2,009
Deferred credits and other liabilities	288	444
Total liabilities	14,991	16,276
Commitments and contingencies		
Stockholders' Equity		
Preferred stock - no shares issued or outstanding (no par value, 26 million shares authorized)	—	—
Common stock:		
Issued – 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 – 95 million and 73 million shares	(3,642)	(2,903)
Additional paid-in capital	6,531	6,592
Retained earnings	17,638	15,135
Accumulated other comprehensive loss	(277)	(250)
Total stockholders' equity	21,020	19,344
Total liabilities and stockholders' equity	$ 36,011	$ 35,620

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

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

	Year Ended December 31,		
(In millions)	2014	2013	2012
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income	$ 3,046	$ 1,753	$ 1,582
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations	(2,077)	(822)	(726)
Deferred income taxes	88	(34)	(34)
Depreciation, depletion and amortization	2,861	2,500	2,008
Impairments	132	96	371
Pension and other postretirement benefits, net	(34)	45	(32)
Exploratory dry well costs and unproved property impairments	623	720	457
Net (gain) loss on disposal of assets	90	29	(127)
Equity method investments, net	27	12	11
Changes in:			
Current receivables	119	217	(481)
Inventories	(11)	(19)	(24)
Current accounts payable and accrued liabilities	(33)	(208)	(102)
All other operating, net	(95)	99	(29)
Net cash provided by continuing operations	4,736	4,388	2,874
Net cash provided by discontinued operations	751	882	1,143
Net cash provided by operating activities	5,487	5,270	4,017
Investing activities:			
Acquisitions, net of cash acquired	(21)	(74)	(1,033)
Additions to property, plant and equipment	(5,160)	(4,443)	(4,361)
Disposal of assets, net of cash transferred to buyer	3,760	450	467
Investments - return of capital	61	61	57
Investing activities of discontinued operations	(376)	(550)	(579)
All other investing, net	(10)	35	10
Net cash used in investing activities	(1,746)	(4,521)	(5,439)
Financing activities:			
Commercial paper, net	(135)	(65)	200
Borrowings	—	—	1,997
Debt issuance costs	—	—	(21)
Debt repayments	(68)	(182)	(145)
Purchases of common stock	(1,000)	(500)	—
Dividends paid	(543)	(508)	(480)
All other financing, net	153	93	49
Net cash provided by (used in) financing activities	(1,593)	(1,162)	1,600
Effect of exchange rate changes on cash:			
Continuing operations	(2)	(3)	7
Discontinued operations	(12)	(4)	6
Net increase (decrease) in cash and cash equivalents	2,134	(420)	191
Cash and cash equivalents at beginning of period	264	684	493
Cash and cash equivalents at end of period	$ 2,398	$ 264	$ 684

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
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 income	—	—	—	—	—	—	(63)	—	(63)
Dividends paid	—	—	—	—	—	(480)	—	—	(480)
Purchase of shares from noncontrolling 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
Other comprehensive loss	—	—	—	—	—	—	183	—	183
Dividends paid	—	—	—	—	—	(508)	—	—	(508)
December 31, 2013 Balance	$ —	$ 770	$ —	$ (2,903)	$ 6,592	$ 15,135	$ (250)	$ —	$ 19,344
Shares issued - stock-based compensation	—	—	—	276	(57)	—	—	—	219
Shares repurchased	—	—	—	(1,015)	—	—	—	—	(1,015)
Stock-based compensation	—	—	—	—	(4)	—	—	—	(4)
Net income	—	—	—	—	—	3,046	—	—	3,046
Other comprehensive income	—	—	—	—	—	—	(27)	—	(27)
Dividends paid	—	—	—	—	—	(543)	—	—	(543)
December 31, 2014 Balance	$ —	$ 770	$ —	$ (3,642)	$ 6,531	$ 17,638	$ (277)	$ —	$ 21,020

(Shares in millions)	Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock
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
Shares issued - stock-based compensation	—	—	—	(7)
Shares repurchased	—	—	—	29
December 31, 2014 Balance	—	770	—	95

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

1. Summary of Principal Accounting Policies

We are a global energy company engaged in exploration, production and marketing of crude oil and condensate, NGLs and natural gas; as well as 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 included as noncurrent assets on the consolidated balance sheet. These 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. As a result of the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014 (see Note 5), these businesses are reflected as discontinued operations in all periods presented.

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

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

Revenue recognition – Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. 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 crude oil and condensate, NGLs 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.

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 – Crude oil and natural gas inventories are recorded at weighted average cost and carried at the lower of cost or market value. The last-in, first-out ("LIFO") method is used for our U.S. crude oil and natural gas inventories. Materials and supplies inventory consist principally of tubular goods and equipment which are valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate.

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.

Fair value hedges – We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio and 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. If significant transfers occur, they would be disclosed in Note 14 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 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, as well as property, plant and equipment unrelated to oil and gas producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets as summarized below.

Type of Asset	Range of Useful Lives
Office furniture, equipment and computer hardware	1 to 15 years
Pipelines	10 to 40 years
Plants, facilities, mine equipment and infrastructure	16 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. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is 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 is 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 – 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. 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.

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.

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 February 2015, the FASB issued an amendment to the guidance for determining whether an entity is a variable interest entity ("VIE"). The standard does not add or remove any of the five characteristics that determine if an entity is a VIE. However, it does change the manner in which a reporting entity assesses one of the characteristics. In particular, when decision-making over the entity's most significant activities has been outsourced, the standard changes how a reporting entity assesses if the equity holders at risk lack decision making rights. This standard is effective for us for annual periods beginning after December 15, 2015 and early adoption is permitted, including in interim periods. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

In August 2014, the FASB issued an update that requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards. This standard is effective for us in the first quarter of 2017 and early adoption is permitted. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

In May 2014, the FASB issued an update that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. Among other things, the standard also eliminates industry-specific revenue guidance, requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. This standard is effective for us in the first quarter of 2017 and should be applied retrospectively to each prior reporting period presented or with the cumulative effect of initially applying the update recognized at the date of initial application. Early adoption is not permitted. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

In April 2014, the FASB issued an amendment to accounting standards that changes the criteria for reporting discontinued operations while enhancing related disclosures. Under the amendment, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Expanded disclosures about the assets, liabilities, income and expenses of discontinued operations will be required. In addition, disclosure of the pretax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting will be made in order to provide users with information about the ongoing trends in an organization's results from continuing operations. The amendments are effective for us in the first quarter of 2015 and early adoption is permitted. We did not elect early adoption of this amendment and do not expect its future adoption to have a significant impact on our consolidated results of operations, financial position or cash flows.

Recently 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 was effective for us beginning in the first quarter of 2014 and is required to be applied prospectively. Adoption of this standard did 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. This accounting standards update was effective for us beginning in the first quarter of 2014 and is required to be applied retrospectively. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

3. 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, 2014 and 2013. 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 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 us. 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 $558 million as of December 31, 2014. 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.

4. Acquisitions

2014 - North America E&P

In an asset acquisition that closed August 2014, we added acreage to the Oklahoma Resource Basins at a cost of approximately $80 million before final settlement adjustments.

In the fourth quarter of 2014, we acquired additional acres in the SCOOP, at a cost of approximately $60 million before final settlement adjustments.

2013 & 2012 - North America E&P

In July 2013, we acquired additional acreage in the Eagle Ford in a transaction valued at $97 million, including a carried interest of $23 million which was fully satisfied in 2014. 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.

During 2012, we acquired approximately 25,000 net acres in the core of the Eagle Ford in several transactions accounted for as business combinations. 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.

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
Current assets:		
Cash	$ 8	$ —
Receivables	22	8
Inventories	1	—
Total current assets acquired	31	8
Property, plant and equipment	822	248
Total assets acquired	853	256
Current liabilities:		
Accounts payable	78	23
Total current liabilities assumed	78	23
Asset retirement obligations	7	1
Total liabilities assumed	85	24
Net assets acquired	$ 768	$ 232

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 and a discount rate of approximately 10 percent. 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.

5. Dispositions

2014 - International E&P

In June 2014, we entered into an agreement to sell our Norway business, including the operated Alvheim FPSO, 10 operated licenses and a number of non-operated licenses on the Norwegian Continental Shelf in the North Sea, with an effective date of January 1, 2014. The transaction closed in the fourth quarter of 2014 for proceeds of $2.1 billion, before netting $589 million cash transferred to the buyer. A $976 million after-tax gain on the sale of Norway business was recorded in the fourth quarter of 2014. Included in this after-tax gain is a deferred tax benefit reflecting our ability to utilize foreign tax credits that otherwise would have needed a valuation allowance.

As part of our agreement to sell our Norway business, we agreed to provide customary transition services to the buyer for an initial period of six months from the closing date. The buyer may extend such services for an additional six months if mutually agreed upon. These services include accounting, marketing, information technology and safety. Amounts received for these transition services are not significant to us. We do not exert influence over the operational and financial policies of the Norway business nor do we retain risk associated with this business.

Our Norway business is reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. Select amounts reported in discontinued operations were as follows:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Revenues applicable to discontinued operations	$ 1,981	$ 3,176	$ 3,726
Pretax income from discontinued operations	$ 1,693	$ 2,537	$ 3,026
Pretax gain on disposition of discontinued operations	$ 1,406	$ —	$ —

In the first quarter of 2014, we closed the sales of our 10 percent non-operated working interests in the Production Sharing Contracts and Joint Operating Agreements for Angola Blocks 31 and 32 for aggregate proceeds of approximately $2 billion. A $532 million after-tax gain on the sale of our Angola assets was recorded in 2014. Included in this after-tax gain is a deferred tax benefit reflecting our ability to utilize foreign tax credits that otherwise would have needed a valuation allowance.

Our Angola operations are reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. Select amounts reported in discontinued operations were as follows:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Revenues applicable to discontinued operations	$ 58	$ 361	$ —
Pretax income (loss) from discontinued operations	$ 51	$ 247	$ (17)
Pretax gain on disposition of discontinued operations	$ 426	$ —	$ —

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

2014 - North America E&P

In June 2014, we closed the sale of non-core acreage located in the far northwest portion of the Williston Basin for proceeds of $90 million. A pretax loss of $91 million was recorded in the second quarter of 2014.

2013 - International E&P

In the fourth quarter of 2013, we transferred our 45 percent working interest and operatorship in the Safen block in the Kurdistan Region of Iraq at a pretax loss of $17 million.

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 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.

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.

2012 - North America E&P

In the third quarter of 2012, we sold non-core 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 in the first quarter of 2012.

6. 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 in all years and stock appreciation rights in 2013 and 2012, provided the effect is not antidilutive. The per share calculations below exclude 4 million, 5 million and 10 million stock options in 2014, 2013 and 2012 that were antidilutive.

	Year Ended December 31,		
(In millions, except per share data)	2014	2013	2012
Income from continuing operations	$ 969	$ 931	$ 856
Discontinued operations	2,077	822	726
Net income	$ 3,046	$ 1,753	$ 1,582
Weighted average common shares outstanding	680	705	706
Effect of dilutive securities	3	4	4
Weighted average common shares, diluted	683	709	710
Per basic share:			
Income from continuing operations	$ 1.42	$ 1.32	$ 1.21
Discontinued operations	$ 3.06	$ 1.17	$ 1.03
Net income	$ 4.48	$ 2.49	$ 2.24
Per diluted share:			
Income from continuing operations	$ 1.42	$ 1.31	$ 1.21
Discontinued operations	$ 3.04	$ 1.16	$ 1.02
Net income	$ 4.46	$ 2.47	$ 2.23

7. Segment Information

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 crude oil and condensate, NGLs and natural gas in North America;
- International E&P ("Int'l E&P") – explores for, produces and markets crude oil and condensate, NGLs 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. Gains or losses on dispositions, certain impairments, unrealized gains or losses on crude oil derivative instruments, or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.

As discussed in Note 5, we closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014, and both are reflected as discontinued operations and excluded from the International E&P segment in all periods presented.

Year Ended December 31, 2014 (In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$ 5,770	$ 1,410	$ 1,556	$ —	$ 8,736
Marketing revenues	1,839	219	52	—	2,110
Total revenues	7,609	1,629	1,608	—	10,846
Income from equity method investments	—	424	—	—	424
Net gain (loss) on disposal of assets and other income	23	57	4	(96) [c]	(12)
Less:					
Production expenses	891	386	969	—	2,246
Marketing costs	1,836	217	52	—	2,105
Exploration expenses	608	185	—	—	793
Depreciation, depletion and amortization	2,342	269	206	44	2,861
Impairments	23	—	—	109 [d]	132
Other expenses [a]	473	197	54	392 [e]	1,116
Taxes other than income	385	—	20	1	406
Net interest and other	—	—	—	238	238
Income tax provision (benefit)	381	288	76	(353)	392
Segment income/Income from continuing operations	$ 693	$ 568	$ 235	$ (527)	$ 969
Capital expenditures [b]	$ 4,698	$ 534	$ 212	$ 51	$ 5,495

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Primarily related to the sale of non-core acreage from our North America E&P segment (see Note 5).
[d] Proved property impairments (see Note 14).
[e] Includes pension settlement loss of $99 million (see Note 19).

Year Ended December 31, 2013 (In millions)	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$ 5,068	$ 2,654	$ 1,576	$ (52) [c]	$ 9,246
Marketing revenues	1,797	264	18	—	2,079
Total revenues	6,865	2,918	1,594	(52)	11,325
Income from equity method investments	—	427	—	(4) [d]	423
Net gain (loss) on disposal of assets and other income	12	50	5	(32) [e]	35
Less:					
Production expenses	797	359	1,000	—	2,156
Marketing costs	1,796	262	18	—	2,076
Exploration expenses	725	166	—	—	891
Depreciation, depletion and amortization	1,927	331	218	24	2,500
Impairments	41	—	—	55 [f]	96
Other expenses [a]	420	161	66	401 [g]	1,048
Taxes other than income	318	—	22	5	345
Net interest and other	—	—	—	278	278
Income tax provision (benefit)	324	1,358	69	(289)	1,462
Segment income/Income from continuing operations	$ 529	$ 758	$ 206	$ (562)	$ 931
Capital expenditures [b]	$ 3,649	$ 456	$ 286	$ 58	$ 4,449

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Unrealized loss on crude oil derivative instruments (see Note 15).
[d] EGHoldings impairment (see Note 14).
[e] Related to the disposal of assets from our North America E&P segment (see Note 5).
[f] Proved property impairments (see Note 14).
[g] Includes pension settlement loss of $45 million (see Note 19).

Year Ended December 31, 2012 *(In millions)*	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$ 3,944	$ 3,719	$ 1,521	$ 53 (c)	$ 9,237
Marketing revenues	2,451	248	30	—	2,729
Total revenues	6,395	3,967	1,551	53	11,966
Income from equity method investments	2	368	—	—	370
Net gain (loss) on disposal of assets and other income	11	21	4	114 (d)	150
Less:					
Production expenses	706	377	996	—	2,079
Marketing costs	2,444	259	31	—	2,734
Exploration expenses	588	97	—	—	685
Depreciation, depletion and amortization	1,428	318	217	45	2,008
Impairments	11	—	—	360 (e)	371
Other expenses [(a)]	400	116	60	464 (f)	1,040
Taxes other than income	226	—	22	(5)	243
Net interest and other	—	—	—	222	222
Income tax provision (benefit)	223	2,294	58	(327)	2,248
Segment income/Income from continuing operations	$ 382	$ 895	$ 171	$ (592)	$ 856
Capital expenditures [(b)]	$ 3,988	$ 235	$ 188	$ 115	$ 4,526

(a) Includes other operating expenses and general and administrative expenses.
(b) Includes accruals.
(c) Unrealized gain on crude oil derivative instruments (see Note 15).
(d) Related to the disposal of assets from our North America E&P and International E&P segments (see Note 5).
(e) Proved property impairments (see Note 14).
(f) Includes pension settlement loss of $45 million (see Note 19).

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)	Year Ended December 31, 2014	2013	2012
United States	$ 7,609	$ 6,813	$ 6,448
Canada	1,608	1,594	1,551
Libya[(a)]	244	1,106	1,989
Other international	1,385	1,812	1,978
Total revenues	$ 10,846	$ 11,325	$ 11,966

(a) See Note 12 for discussion of Libya operations.

In 2014, sales to Shell Oil and its affiliates accounted for approximately 10 percent of our total revenues. In 2013, Statoil, the purchaser of the majority of our Libyan crude oil, accounted for approximately 10 percent of our total revenues. In 2012, Statoil 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.

Revenues by product line were:

(In millions)	Year Ended December 31, 2014	2013	2012
Crude oil and condensate	$ 8,170	$ 8,688	$ 9,301
Natural gas liquids	371	313	201
Natural gas	693	693	835
Synthetic crude oil	1,525	1,542	1,409
Other	87	89	220
Total revenues	$ 10,846	$ 11,325	$ 11,966

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

	December 31,	
(In millions)	2014	2013
United States	$ 16,518	$ 14,635
Canada	9,802	9,794
Norway [(a)]	—	977
Equatorial Guinea	1,949	1,977
Other international	1,884	1,963
Total long-lived assets	$ 30,153	$ 29,346

(a) Decrease in 2014 is due to the previously discussed sale of our Norway business.

8. Other Items

Net interest and other

	Year Ended December 31,		
(In millions)	2014	2013	2012
Interest:			
Interest income	$ 7	$ 5	$ 12
Interest expense	(297)	(299)	(241)
Income on interest rate swaps	12	9	7
Interest capitalized	20	12	9
Total interest	(258)	(273)	(213)
Other:			
Net foreign currency gains	21	14	2
Write off of contingent proceeds	—	(4)	—
Other	(1)	(15)	(11)
Total other	20	(5)	(9)
Net interest and other	$ (238)	$ (278)	$ (222)

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
Net interest and other	$ 21	$ 14	$ 2
Provision for income taxes	(12)	(2)	2
Aggregate foreign currency gains	$ 9	$ 12	$ 4

9. Income Taxes

Income tax provisions (benefits) for continuing operations were:

	Year Ended December 31,								
	2014			2013			2012		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ 15	$ 62	$ 77	$ 83	$ (47)	$ 36	$ (47)	$ 43	$ (4)
State and local	8	(58)	(50)	39	(6)	33	(34)	48	14
Foreign	281	84	365	1,374	19	1,393	2,363	(125)	2,238
Total	$ 304	$ 88	$ 392	$ 1,496	$ (34)	$ 1,462	$ 2,282	$ (34)	$ 2,248

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:

	Year Ended December 31,		
	2014	2013	2012
Statutory rate applied to income from continuing operations before income taxes	35%	35%	35%
Effects of foreign operations, including foreign tax credits	(6)	26	36
Change in permanent reinvestment assertion	(19)	—	—
Adjustments to valuation allowances	21	(1)	—
Other	(2)	1	1
Effective income tax rate on continuing operations	29%	61%	72%

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. 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 7.

Effects of foreign operations – The effects of foreign operations on our effective tax rate decreased in 2014 and 2013 as compared to 2012, due to a shift in pretax income mix between high and low tax jurisdictions. This is primarily related to decreased sales in Libya in 2014 and 2013 where the tax rate is in excess of 90 percent. Excluding Libya, the effective tax rates on continuing operations for 2014, 2013 and 2012 would be 27 percent, 38 percent and 37 percent.

Change in permanent reinvestment assertion – In the second quarter of 2014, we reviewed our foreign operations, including the disposition of our Norway business, and concluded that our foreign operations do not have the same level of immediate capital needs as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings associated with our U.K. operations to be permanently reinvested outside the U.S. The U.K. statutory tax rate is in excess of the U.S. statutory tax rate and therefore foreign tax credits associated with these earnings exceeds any incremental U.S. tax liabilities.

Adjustments to valuation allowances – In 2014, we increased the valuation allowance against foreign tax credits as a result of removing the permanent reinvestment assertion on our U.K. operations since the U.K. statutory tax rate is in excess of the U.S. statutory tax rate per discussion above. In 2013, valuation allowances decreased primarily due to the disposal of our Indonesian assets.

Deferred tax assets and liabilities resulted from the following:

	Year Ended December 31,	
(In millions)	2014	2013
Deferred tax assets:		
Employee benefits	$ 364	$ 387
Operating loss carryforwards	245	284
Capital loss carryforwards	89	3
Foreign tax credits	4,062	5,730
Other	116	95
Valuation allowances:		
Federal	(2,775)	(2,997)
State, net of federal benefit	(58)	(67)
Foreign	(108)	(149)
Total deferred tax assets	1,935	3,286
Deferred tax liabilities:		
Property, plant and equipment	3,737	4,018
Investments in subsidiaries and affiliates	66	794
Other	67	67
Total deferred tax liabilities	3,870	4,879
Net deferred tax liabilities	$ 1,935	$ 1,593

Tax carryforwards – At December 31, 2014 our operating loss carryforwards included $570 million from Canada that expire in 2029 through 2032, $180 million from the Kurdistan Region of Iraq that expire in 2016 through 2019 and $41 million from E.G. that expire in 2017 through 2019. State operating loss carryforwards of $1,293 million expire in 2015 through 2033. Foreign tax credit carryforwards of $3,550 million expire in 2022 through 2024.

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 decreased $222 million in 2014 primarily due to the sale of our Norway and Angola businesses. Federal valuation allowances increased $930 million and $1,277 million in 2013 and 2012, 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 $41 million in 2014 primarily due to the disposal of our Angola assets. Foreign valuation allowances decreased $61 million in 2013 primarily due the disposal of our Indonesian assets. Foreign valuation allowances increased $16 million in 2012 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)	2014	2013
Assets:		
Other current assets	$ 29	$ 53
Other noncurrent assets	525	847
Liabilities:		
Other current liabilities	3	1
Noncurrent deferred tax liabilities	2,486	2,492
Net deferred tax liabilities	$ 1,935	$ 1,593

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.

As of December 31, 2014 our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[(a)]	2004-2013
Canada	2009-2013
Equatorial Guinea	2007-2013
Libya	2012-2013
United Kingdom	2008-2013

(a) Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2014	2013	2012
Beginning balance	$ 146	$ 98	$ 157
Additions for tax positions related to the current year	—	14	—
Additions for tax positions of prior years	11	66	81
Reductions for tax positions of prior years	(68)	(25)	(67)
Settlements	(9)	(5)	(72)
Statute of limitations	—	(2)	(1)
Ending balance	$ 80	$ 146	$ 98

If the unrecognized tax benefits as of December 31, 2014 were recognized, $37 million would affect our effective income tax rate. There were $5 million of uncertain tax positions as of December 31, 2014 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 $6 million, $13 million and $4 million related to unrecognized tax benefits in 2014, 2013 and 2012. As of December 31, 2014 and 2013, $16 million and $15 million of interest and penalties were accrued related to income taxes.

Pretax income from continuing operations included amounts attributable to foreign sources of $1,180 million, $2,336 million and $3,356 million in 2014, 2013 and 2012.

Undistributed income of certain Canadian foreign subsidiaries at December 31, 2014 amounted to $1,019 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 $357 million would be recorded, not including potential utilization of foreign tax credits.

10. Inventories

Inventories of liquid hydrocarbons, natural gas and bitumen are carried at the lower of cost or market value. The LIFO method accounted for 6 percent and 4 percent of total inventory value at December 31, 2014 and 2013. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2014 and 2013 by $20 million and $32 million.

	December 31,	
(In millions)	2014	2013
Liquid hydrocarbons, natural gas and bitumen	$ 58	$ 55
Supplies and other items	299	309
Inventories at cost	$ 357	$ 364

11. Equity Method Investments and Related Party Transactions

During 2014, 2013 and 2012 only our equity method investees were considered related parties and they included:

- EGHoldings, in which we have a 60 percent noncontrolling interest. EGHoldings is engaged in LNG production activity.
- 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.

Our equity method investments are summarized in the following table:

	Ownership as of	December 31,	
(In millions)	December 31, 2014	2014	2013
EGHoldings	60%	$ 693	$ 748
Alba Plant LLC	52%	225	263
AMPCO	45%	194	189
Other investments		1	1
Total		$ 1,113	$ 1,201

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $451 million in 2014, $435 million in 2013 and $381 million in 2012.

Summarized financial information for equity method investees is as follows:

(In millions)	2014	2013	2012
Income data – year:			
Revenues and other income	$ 1,349	$ 1,444	$ 1,330
Income from operations	826	849	755
Net income	728	727	635
Balance sheet data – December 31:			
Current assets	$ 639	$ 644	
Noncurrent assets	1,461	1,590	
Current liabilities	371	384	
Noncurrent liabilities	39	33	

Revenues from related parties were $56 million, $55 million and $58 million in 2014, 2013 and 2012, with the majority related to EGHoldings in all years. Purchases from related parties were $207 million, $242 million and $248 million in 2014, 2013 and 2012 with the majority related to Alba Plant LLC in all years.

Current receivables from related parties at December 31, 2014 and 2013, approximately split evenly between EGHoldings and AMPCO, were $31 million, and $30 million. Payables to related parties were $11 million and $20 million at December 31, 2014 and 2013, with the majority related to Alba Plant LLC.

12. Property, Plant and Equipment

	December 31,	
(In millions)	2014	2013
North America E&P	$ 16,717	$ 14,973
International E&P [a]	2,741	3,590
Oil Sands Mining	9,455	9,447
Corporate	127	135
Net property, plant and equipment	$ 29,040	$ 28,145

[a] International E&P decrease is due to the sale of our Norway business in the fourth quarter of 2014.

Beginning in the third quarter of 2013, our Libya operations were impacted by third-party labor strikes at the Es Sider oil terminal. In early July 2014, Libya's National Oil Corporation rescinded force majeure associated with the third-party labor strikes, and our concession term was extended for slightly more than one year. Although we had five liftings during 2014, in December 2014, Libya's National Oil Corporation once again declared force majeure at Es Sider as disruptions from civil unrest continue. Considerable uncertainty remains around the timing of future production and sales levels.

As of December 31, 2014, our net property, plant and equipment investment in Libya is approximately $771 million, and total proved reserves (unaudited) in Libya are 243 mmboe. We and our partners in the Waha concessions continue to assess the situation and the condition of our assets in Libya. Our periodic assessment of the carrying value of our net property, plant and equipment in Libya specifically considers the net investment in the assets, the duration of our concessions and the reserves anticipated to be recoverable in future periods. The undiscounted cash flows related to our Libya assets continues to exceed the carrying value of $771 million by a material amount.

Deferred exploratory well costs were as follows:

	December 31,		
(In millions)	2014	2013	2012
Amounts capitalized less than one year after completion of drilling	$ 484	$ 512	$ 388
Amounts capitalized greater than one year after completion of drilling	126	281	229
Total deferred exploratory well costs	$ 610	$ 793	$ 617
Number of projects with costs capitalized greater than one year after completion of drilling	3	7	6

(In millions)	2014	2013	2012
Beginning balance	$ 793	$ 617	$ 704
Additions	808	746	699
Dry well expense	(206)	(147)	(111)
Transfers to development	(605)	(414)	(629)
Dispositions[(a)]	(180)	(9)	(46)
Ending balance	$ 610	$ 793	$ 617

(a) We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014.

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2014 are summarized by geographical area below:

(In millions)	
Gabon	$ 66
E.G.	22
Canada	38
Total	$ 126

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

Gabon - The Diaba-1B well reached total depth in the third quarter of 2013. We are analyzing new 3D seismic, integrated with existing technical data, in order to finalize the next steps in the exploration program on the offshore Diaba License.

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 and expected to begin in 2015.

Canada **–** Exploration costs related to our Canadian in-situ assets at Birchwood accumulated 2010 through 2012. 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 2015. Upon receiving this approval, we will further evaluate our development plans.

13. Goodwill

Goodwill is tested for impairment on an annual basis as of April 1 each year, or when events or changes in circumstances indicate the fair value of a reporting unit with goodwill may have been reduced below its carrying value. Goodwill is tested for impairment at the reporting unit level. Our reporting units are the same as our reporting segments, of which only North America E&P and International E&P include goodwill. We estimate the fair values of the North America E&P and International E&P reporting units using an income approach. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. The discounted cash flows that served as the primary basis for the income approach were based on forecasted assumptions. Key assumptions include: future liquid hydrocarbon and natural gas prices, estimated quantities of liquid hydrocarbon and natural gas proved and probable reserves, expected timing of production, discount rates, future capital requirements and operating expenses and tax rates. These assumptions used to determine fair value estimates are consistent with those that management uses to make business decisions. We believe the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

We performed our annual impairment tests during 2014, 2013 and 2012 and no impairment was required. The fair value of each of our reporting units with goodwill exceeded the book value.

The table below displays the allocated beginning goodwill balances by segment along with changes in the carrying amount of goodwill for 2014 and 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
2014				
Beginning balance, gross	$ 347	$ 152	$ 1,412	$ 1,911
Less: accumulated impairments	—	—	(1,412)	(1,412)
Beginning balance, net	347	152	—	499
Dispositions	(3)	(37)	—	(40)
Ending balance, net	$ 344	$ 115	$ —	$ 459

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

After we performed our annual impairment test in April 2014, there was a substantial decline in commodity prices. The resulting change in future commodity price assumptions was a triggering event which required us to reassess our goodwill for impairment as of December 31, 2014. Based on the results of this assessment, we concluded no impairment was required. The fair value of each of our reporting units with goodwill exceeded the book value by a significant amount. A period of sustained reduced commodity prices could result in non-cash impairment charges related to goodwill in future periods.

14. 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, 2014 and 2013 by fair value hierarchy level.

	December 31, 2014			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Interest rate	$ —	$ 8	$ —	$ 8
Derivative instruments, assets	$ —	$ 8	$ —	$ 8

	December 31, 2013			
(In millions)	Level 1	Level 2	Level 3	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

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.

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.

	2014		2013		2012	
(In millions)	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 43	$ 132	$ 5	$ 96	$ 16	$ 371

The substantial decline in commodity prices during the second half of 2014, and the resulting change in future commodity price assumptions, was a triggering event which required us to reassess long-lived assets related to oil and gas producing properties for impairment as of December 31, 2014. We estimated the fair values using an income approach and concluded that no material impairments were required. A period of sustained reduced commodity prices could result in non-cash impairment charges related to long-lived assets in future periods.

North America E&P

Long-lived assets held for use – Fair values are 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 include reserve and production estimates made by our reservoir engineers, estimated future commodity prices adjusted for quality and location differentials, and forecasted operating expenses for the remaining estimated life of the reservoir.

In the third quarter of 2014, impairments of $53 million were recorded to Gulf of Mexico properties as a result of estimated abandonment cost and other revisions, to an aggregate fair value of $19 million. In addition, two fields were impaired a total of $47 million to an aggregate fair value of $24 million primarily due to lower forecasted commodity prices.

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 assets' remaining value.

During 2012, the Ozona development, offshore Gulf of Mexico, produced toward abandonment pressures, and downward revisions of reserves were taken for an aggregate impairment of $289 million. Ozona production ceased in the first quarter of 2013 and an additional $21 million impairment was recorded. During 2014, we recorded additional impairments of $30 million at Ozona as a result of estimated abandonment cost revisions.

Other impairments of long-lived assets held for use in 2014, 2013 and 2012 were a result of reduced drilling expectations, reductions of estimated reserves or decreased commodity prices.

International E&P

Long-lived assets held for use – In the fourth quarter of 2013, as a result of E.G.'s natural gas policy related to the country's 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 addition, our share of income from EGHoldings included a $4 million impairment related to the same project, reflected in income from equity method investments in the 2013 consolidated statement of income.

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, 2014 and 2013.

	December 31,			
	2014		2013	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other noncurrent assets	$ 132	$ 129	$ 154	$ 147
Total financial assets	$ 132	$ 129	$ 154	$ 147
Financial liabilities				
Other current liabilities	$ 13	$ 13	$ 13	$ 13
Long-term debt, including current portion[(a)]	6,887	6,360	6,922	6,427
Deferred credits and other liabilities	69	68	149	147
Total financial liabilities	$ 6,969	$ 6,441	$ 7,084	$ 6,587

(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.

15. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 14. 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, 2014 and 2013, 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, 2014 and 2013.

	December 31, 2014			
(In millions)	Asset	Liability	**Net Asset**	Balance Sheet Location
Fair Value Hedges			—	
Interest rate	$ 8	$ —	$ 8	Other noncurrent assets
Total Designated Hedges	$ 8	$ —	$ 8	

	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	

Derivatives Designated as Fair Value Hedges

The following table presents by maturity date, information about our interest rate swap agreements, including the weighted average, London Interbank Offer Rate ("LIBOR")-based, floating rate.

	December 31, 2014		December 31, 2013	
Maturity Dates	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate	Aggregate Notional Amount (in millions)	Weighted Average, LIBOR-Based, Floating Rate
October 2, 2017	$ 600	4.64%	$ 600	4.65%
March 15, 2018	$ 300	4.49%	$ 300	4.50%

As of December 31, 2013 our foreign currency forwards had an aggregate notional amount of 2,387 million Norwegian Kroner at a weighted average forward rate of 6.060. These forwards hedged the current Norwegian tax liability of the subsidiary that held our Norway business. There were none outstanding at December 31, 2014 as the open positions were transfered to the purchaser of our Norway business upon closing of the sale in the fourth quarter of 2014.

The pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income is summarized in the table below. There is no ineffectiveness related to the fair value hedges.

		Gain (Loss)		
		Year Ended December 31,		
(In millions)	Income Statement Location	2014	2013	2012
Derivative				
Interest rate	Net interest and other	$ —	$ (13)	$ 16
Foreign currency	Discontinued operations	(36)	(44)	(1)
Hedged Item				
Long-term debt	Net interest and other	$ —	$ 13	$ (16)
Accrued taxes	Discontinued operations	36	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 expired in December 2013. We had no crude oil derivative instruments during 2014.

The impact of commodity derivative instruments not designated as hedges appears in sales and other operating revenues in our consolidated statements of income and was a net loss of $67 million in 2013 and a net gain of $70 million in 2012.

16. Debt

Short-term debt

As of December 31, 2014, we had no borrowings against our revolving credit facility, as described below, or under our U.S. commercial paper program that is backed by the revolving credit facility.

Long-term debt

In May 2014, we amended our $2.5 billion unsecured revolving credit facility (the "Credit Facility"), including an extension of the maturity to May 2019. Terms of this amended Credit Facility include the ability to request two one-year extensions, an option to increase the commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, and sub-facilities for swing-line loans and letters of credit up to an aggregate amount of $100 million and $500 million. Fees on the unused commitment of each lender range from 8 basis points to 22.5 basis points depending on our credit ratings. Borrowings under the Credit Facility bear interest, at our option, at either (a) an adjusted LIBOR rate plus a margin ranging from 87.5 basis points to 150 basis points depending on our credit ratings or (b) the Base Rate plus a margin ranging from 0 basis points to 50 basis points depending on our credit ratings. Base Rate is defined as a per annum rate equal to the greatest of (a) the prime rate, (b) the federal funds rate plus one-half of one percent or (c) LIBOR for a one-month interest period plus 1 percent.

The Credit Facility 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 holding more than half of the commitments 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. We are in compliance with this covenant as of December 31, 2014.

The following table details our long-term debt:

	December 31,	
(In millions)	2014	2013
Senior unsecured notes:		
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 2015 – 2049	9	10
Other obligations:		
4.550% promissory note, semi-annual payments due 2015	68	136
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Total[(b)]	6,377	6,446
Unamortized discount	(8)	(9)
Fair value adjustments[(c)]	22	25
Amounts due within one year	(1,068)	(68)
Total long-term debt	$ 5,323	$ 6,394

(a) These notes contain a make-whole provision allowing us 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, 2014 may be declared immediately due and payable.
(c) See Notes 14 and 15 for information on interest rate swaps.

The following table shows future long-term debt payments:

(In millions)	
2015	$ 1,068
2016	—
2017	682
2018	854
2019	228
Thereafter	3,545
Total long-term debt, including current portion	$ 6,377

17. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)	2014	2013
Beginning balance	$ 2,096	$ 1,783
Incurred, including acquisitions	89	84
Settled, including dispositions[(a)]	(426)	(78)
Accretion expense (included in depreciation, depletion and amortization)	104	106
Revisions to previous estimates	95	244
Held for sale	—	(43)
Ending balance[(b)]	$ 1,958	$ 2,096

(a) Includes the sale of our Norway business in the fourth quarter of 2014.
(b) Includes asset retirement obligations of $41 million and $87 million classified as short-term at December 31, 2014 and 2013.

18. Supplemental Cash Flow Information

	Year Ended December 31,		
(In millions)	2014	2013	2012
Net cash provided by operating activities:			
Interest paid (net of amounts capitalized)	$ 289	307	$ 225
Income taxes paid to taxing authorities [(a)]	1,679	3,904	4,974
Commercial paper, net:			
Issuances	$ 2,345	$ 10,870	$ 13,880
Repayments	(2,480)	(10,935)	(13,680)
Commercial paper, net	$ (135)	$ (65)	$ 200
Noncash investing activities, related to continuing operations:			
Asset retirement costs capitalized	151	290	199
Change in capital expenditure accrual	335	6	165
Liabilities assumed in acquisitions	—	—	109
Asset retirement obligations assumed by buyer	359	92	8
Debt payments made by United States Steel	—	—	20

(a) Income taxes paid to taxing authorities includes $1,312 million, $2,270 million and $2,336 million in 2014, 2013, and 2012 related to discontinued operations.

19. 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 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 $1,403 million and $1,359 million as of December 31, 2014 and 2013.

As of December 31, 2014 and 2013, our U.S. plans had accumulated benefit obligations in excess of plan assets. Summary information for these defined benefit pension plans follows.

	December 31,	
(In millions)	2014	2013
Projected benefit obligation	$ (894)	$ (933)
Accumulated benefit obligation	(793)	(791)
Fair value of plan assets	574	625

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

	Pension Benefits					
	2014		2013		Other Benefits	
(In millions)	U.S.	Int'l	U.S.	Int'l	2014	2013
Change in benefit obligations:						
Beginning balance	$ 933	$ 649	$ 1,146	$ 565	$ 279	$ 311
Service cost	31	16	33	22	3	4
Interest cost	35	27	40	24	13	12
Plan amendment[(a)]	—	—	—	—	(42)	—
Actuarial loss (gain)[(b)]	174	46	(140)	40	42	(31)
Foreign currency exchange rate changes	—	(39)	—	11	—	—
Divestiture[(c)]	—	(29)	—	—	—	—
Benefits paid	(279)	(19)	(146)	(13)	(16)	(17)
Ending balance	$ 894	$ 651	$ 933	$ 649	$ 279	$ 279
Change in fair value of plan assets:						
Beginning balance	$ 625	$ 597	$ 630	$ 500	$ —	$ —
Actual return on plan assets	59	59	65	74	—	—
Employer contributions	169	37	76	23	—	—
Foreign currency exchange rate changes	—	(39)	—	13	—	—
Divestiture[(c)]	—	(13)	—	—	—	—
Benefits paid	(279)	(19)	(146)	(13)	—	—
Ending balance	$ 574	$ 622	$ 625	$ 597	$ —	$ —
Funded status of plans at December 31	$ (320)	$ (29)	$ (308)	$ (52)	$ (279)	$ (279)
Amounts recognized in the consolidated balance sheets:						
Current liabilities	(11)	—	(16)	—	(19)	(19)
Noncurrent liabilities	(309)	(29)	(292)	(52)	(260)	(260)
Accrued benefit cost	$ (320)	$ (29)	$ (308)	$ (52)	$ (279)	$ (279)
Pretax amounts in accumulated other comprehensive loss:						
Net loss (gain)	$ 283	$ 91	$ 262	$ 59	$ 34	$ (8)
Prior service cost (credit)	10	8	15	9	(41)	(5)

(a) Represents a change in plan design related to the health care benefits provided under the postretirement plan.
(b) Includes the increase in the U.S. pension and postretirement benefit obligations of $13 million and $15 million respectively, due to the adoption of the 2014 mortality table.
(c) Related to the sale of our Norway business in the fourth quarter of 2014.

Components of net periodic benefit cost from continuing operations 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								
	Year Ended December 31,						Other Benefits		
	2014		2013		2012		Year Ended December 31,		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2014	2013	2012
Components of net periodic benefit cost:									
Service cost	$ 31	$ 16	$ 33	$ 17	$ 31	$ 15	$ 3	$ 4	$ 4
Interest cost	35	27	40	23	42	22	13	12	14
Expected return on plan assets	(34)	(32)	(43)	(24)	(43)	(23)	—	—	—
Amortization:									
- prior service cost (credit)	5	1	6	1	7	1	(6)	(6)	(7)
- actuarial loss	29	1	43	4	48	4	—	—	—
Net settlement loss[a]	99	—	45	—	45	—	—	—	—
Net periodic benefit cost[b]	$ 165	$ 13	$ 124	$ 21	$ 130	$ 19	$ 10	$ 10	$ 11
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)[c]	$ 149	$ 33	$(161)	$ (15)	$ 172	$ 14	$ 42	$ (31)	$ 7
Amortization of actuarial (loss) gain	(128)	(1)	(88)	(4)	(93)	(4)	—	—	—
Prior service cost (credit)	—	—	—	—	—	1	(42)	—	—
Amortization of prior service credit (cost)	(5)	(1)	(6)	(1)	(7)	(1)	6	6	7
Total recognized in other comprehensive (income) loss	$ 16	$ 31	$(255)	$ (20)	$ 72	$ 10	$ 6	$ (25)	$ 14
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$ 181	$ 44	$(131)	$ 1	$ 202	$ 29	$ 16	$ (15)	$ 25

(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. pension plans in all periods presented.
(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 the impact of the sale of our Norway business in the fourth quarter of 2014.

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 2015 are $27 million and $6 million. The estimated net loss and 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 2015 are $1 million and $4 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 2014, 2013 and 2012.

	Pension Benefits								
	2014		2013		2012		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2014	2013	2012
Weighted average assumptions used to determine benefit obligation:									
Discount rate	3.71%	3.70%	4.28%	4.60%	3.44%	4.40%	4.01%	4.85%	4.06%
Rate of compensation increase	4.00%	3.60%	5.00%	4.90%	5.00%	4.50%	4.00%	5.00%	5.00%
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	3.98%	4.60%	3.79%	4.40%	4.21%	4.70%	4.69%	4.06%	4.90%
Expected long-term return on plan assets	6.75%	5.70%	7.25%	4.90%	7.75%	5.20%	—	—	—
Rate of compensation increase	5.00%	4.90%	5.00%	4.50%	5.00%	4.30%	5.00%	5.00%	5.00%

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.

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 weighted average health care cost trend rates

	2014	2013	2012
Initial health care trend rate	6.88%	6.89%	7.24%
Ultimate trend rate	5.00%	5.00%	5.00%
Year ultimate trend rate is reached	2024	2020	2019

Prior to a recent plan amendment, the assumed health care cost trend rates had a significant effect on the amounts reported for our defined benefit retiree health care plans. After the plan amendment, the employer provided subsidy for post-65 retiree health care coverage will only increase by the consumer price index (not to exceed 4 percent) each year. Company contributions would be funded to a Health Reimbursement Account on the retiree's behalf to subsidize the retiree's cost of obtaining health care benefits through a private exchange. Therefore, a one-percentage-point change in health care cost trend rates would not have a material impact on either the service and interest cost components and the postretirement benefit obligations.

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 plan's 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 – The plan's current targeted asset allocation is comprised of 55 percent equity securities and 45 percent other fixed income securities. Over time, as the plan's funded ratio (as defined by the investment policy) improves, in order to reduce volatility in returns and to better match the plan's liabilities, the allocation to equity securities will decrease while the amount allocated to fixed income securities will increase. The plan's assets are managed by a third-party investment manager. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

International plan – Our international plan's target asset allocation is comprised of 62.5 percent equity securities and 37.5 percent fixed income securities. The plan assets are invested in eight separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers. 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, 2014 and 2013.

Cash and cash equivalents – Cash and cash equivalents are valued using a market approach and are considered Level 1. This investment also includes a cash reserve account (a collective short-term investment fund) that is valued using an income approach and is considered Level 2.

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. 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. 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 are therefore considered Level 1.

Pooled funds – Investments in pooled funds are valued using a market approach at the net asset value ("NAV") of units held. 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 ("ETFs") are valued at the closing price reported in an active market, and are considered Level 1. Corporate bonds and other bonds are valued using calculated yield curves created by models that incorporate various market factors and 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 of an equity and fixed income portfolio with underlying investments held in U.S. and non-U.S. securities.

Other – Other investments are composed of an international insurance carrier contract and the majority of the underlying investments consist of a 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 other investments, an unallocated annuity contract, two limited liability companies and real estate are considered Level 3, as inputs to determine fair value are unobservable and significant to the overall fair value measurement.

The following tables present the fair values of our defined benefit pension plan's assets, by level within the fair value hierarchy, as of December 31, 2014 and 2013.

	December 31, 2014							
(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	$ 26	$ 1	$ —	$ —	$ —	$ —	$ 26	$ 1
Equity securities:								
Common and preferred stock[(a)]	230	—	—	—	—	—	230	—
Private equity	—	—	—	—	25	—	25	—
Mutual and pooled funds[(b)]	—	221	—	164	—	—	—	385
Fixed income securities:								
U.S. treasury notes and ETFs	33	—	—	—	—	—	33	—
Corporate and other bonds[(c)]	—	—	190	—	—	—	190	—
Commingled and pooled funds[(d)]	—	—	40	236	—	—	40	236
Other	—	—	—	—	30	—	30	—
Total investments, at fair value	$ 289	$ 222	$ 230	$ 400	$ 55	$ —	$ 574	$ 622

	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 and preferred stock[(a)]	292	—	—	—	—	—	292	—
REIT and private equity	2	—	—	—	23	—	25	—
Mutual and pooled funds[(b)]	—	219	—	186	—	—	—	405
Fixed income securities:							—	—
U.S. treasury notes and ETFs	65	—	—	—	—	—	65	—
Corporate and other bonds[(c)]	—	—	172	—	—	—	172	—
Commingled and pooled funds[(d)]	—	—	17	178	—	—	17	178
Other	—	—	—	13	34	—	34	13
Total investments, at fair value	$ 378	$ 220	$ 190	$ 377	$ 57	$ —	$ 625	$ 597

(a) Primarily investments held in U.S. and non-U.S. common stocks in diverse industries.
(b) Mutual funds - Primarily investments held in U.S. and non-U.S. common stocks in diverse industries.
Pooled funds - Primarily investments held in non-U.S. publicly traded common stocks in diverse industries.
(c) Corporate bonds - Primarily investments held in U.S. and non-U.S. corporate bonds in diverse industries.
Other bonds - Primarily consist of securities issued by governmental agencies and municipalities.
(d) Pooled funds - Primarily investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds.

The activity during the year ended December 31, 2014 and 2013, for the assets using Level 3 fair value measurements was immaterial.

Cash flows

Estimated future benefit payments – The following gross benefit payments, which were estimated based on actuarial assumptions applied at December 31, 2014 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
2015	$ 80	$ 15	$ 19
2016	78	17	19
2017	83	19	19
2018	79	22	19
2019	74	23	19
2020 through 2024	299	128	93

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $95 million in 2015. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $11 million and $19 million in 2015.

Contributions to defined contribution plan – We contribute to a defined contribution plan for eligible employees. Contributions to this plan totaled $24 million, $26 million and $25 million in 2014, 2013 and 2012.

20. 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 stock awards (including restricted stock and restricted stock unit awards), 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 or 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 we 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.

Prior to 2005, we granted SARs under the 2003 Plan. No SARs have been granted since then and at December 31, 2014 there are no additional SARs outstanding. 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 we previously granted such awards under certain of the Prior Plans. The restricted stock awards granted to 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 ratably 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. 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. 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. 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 $70 million, $70 million and $67 million in 2014, 2013 and 2012, while the total related income tax benefits were $25 million, $25 million and $24 million in the same years. In 2014, 2013 and 2012, cash received upon exercise of stock option awards was $136 million, $58 million and $41 million. Tax benefits realized for deductions for stock awards exercised during 2014, 2013 and 2012 totaled $51 million, $36 million and $24 million.

Stock option awards – During 2014, 2013 and 2012, 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:

	2014	2013	2012
Exercise price per share	$34.49	$33.54	$33.52
Expected annual dividend yield	2.3%	2.1%	2.2%
Expected life in years	5.9	6.1	5.5
Expected volatility	38%	38%	41%
Risk-free interest rate	1.8%	1.6%	1.2%
Weighted average grant date fair value of stock option awards granted	$10.50	$10.25	$10.86

The following is a summary of stock option award activity in 2014.

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Average Intrinsic Value *(in millions)*
Outstanding at beginning of year	18,104,887	$27.27		
Granted	1,935,895	$34.49		
Exercised	(5,959,647)	$23.43		
Canceled	(653,299)	$34.05		
Outstanding at end of year	13,427,836	$29.68	5 years	$ 39
Exercisable at end of year	10,435,751	$28.39	4 years	$ 39
Expected to vest	2,914,069	$34.18	8 years	$ —

The intrinsic value of stock option awards exercised during 2014, 2013 and 2012, was $83 million, $35 million and $40 million.

As of December 31, 2014, unrecognized compensation cost related to stock option awards was $18 million, which is expected to be recognized over a weighted average period of two years.

Restricted stock awards – The following is a summary of restricted stock award activity in 2014.

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	4,031,888	$31.80
Granted	1,970,880	$34.98
Vested	(1,845,327)	$30.64
Forfeited	(709,088)	$32.73
Unvested at end of year	3,448,353	$34.04

The vesting date fair value of restricted stock awards which vested during 2014, 2013 and 2012 was $70 million, $59 million and $36 million. The weighted average grant date fair value of restricted stock awards was $34.04, $31.80, and $29.02 for awards unvested at December 31, 2014, 2013 and 2012.

As of December 31, 2014 there was $82 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of two years.

Stock-based performance unit awards – During 2014 and 2013, we granted 221,491 and 353,600 stock-based performance unit awards to officers. At December 31, 2014, there were 276,331 units outstanding.

The key assumptions used in the Monte Carlo simulation to determine the fair value of stock-based performance units granted in 2014 and 2013 were:

	2014	2013
Valuation date stock price	$28.29	$28.29
Expected annual dividend yield	2.9%	2.9%
Expected volatility	26%	27%
Risk-free interest rate	0.7%	0.3%
Fair value of stock-based performance units outstanding	$25.06	$21.06

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 $5 million, $9 million and $12 million, in 2014, 2013 and 2012. At December 31, 2014 all performance periods have ended and no additional units will be granted.

21. Reclassifications Out of Accumulated Other Comprehensive Loss

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

(In millions)	Year Ended December 31, 2014	2013	Income Statement Line
Accumulated Other Comprehensive Loss Components			
	Income (Expense)		
Postretirement and postemployment plans			
Amortization of actuarial loss	$ (30)	$ (47)	General and administrative
Net settlement loss	(99)	(45)	General and administrative
	(129)	(92)	Income from operations
	62	34	Provision for income taxes
Other insignificant items, net of tax	(1)	(1)	
Total reclassifications for the period	$ (68)	$ (59)	Income from continuing operations

22. Stockholders' Equity

In 2014 we acquired 29 million common shares at a cost of $1 billion under our share repurchase program, initially authorized in 2006, bringing our total repurchases to 121 million common shares at a cost of $4.7 billion. As of December 31, 2014 the total remaining share repurchase authorization was $1.5 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.

23. Leases

We lease a wide variety of facilities and equipment under operating leases, including land, building space, equipment and vehicles. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations 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
2015	$ 1	$ 40
2016	1	33
2017	1	26
2018	1	24
2019	1	24
Later years	19	32
Sublease rentals	—	(3)
Total minimum lease payments	$ 24	$ 176
Less imputed interest costs	(15)	
Present value of net minimum lease payments	$ 9	

Operating lease rental expense related to continuing operations was $120 million, $105 million and $98 million in 2014, 2013 and 2012.

24. Commitments and Contingencies

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

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, 2014 and 2013, 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 $57 million as of December 31, 2014. 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, 2014 and 2013, contractual commitments to acquire property, plant and equipment totaled $747 million and $1,270 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. At December 31, 2014, the remaining liability is $24 million.

Select Quarterly Financial Data (Unaudited)

	2014				2013			
(In millions, except per share data)	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
Revenues	$ 2,690	$ 2,888	$ 2,870	$ 2,398	$ 2,880	$ 3,010	$ 3,000	$ 2,435
Income (loss) from continuing operations before income taxes	598	511	453	(201)	608	804	755	226
Income (loss) from continuing operations	398	360	304	(93)	158	241	396	136
Discontinued operations [a]	751	180	127	1,019	225	185	173	239
Net income	$ 1,149	$ 540	$ 431	$ 926	$ 383	$ 426	$ 569	$ 375
Income (loss) per share:								
Basic:								
Continuing operations	$0.58	$0.53	$0.45	$(0.14)	$0.22	$0.34	$0.56	$0.20
Discontinued operations [a]	$1.08	$0.27	$0.19	$1.51	$0.32	$0.26	$0.24	$0.34
Net income	$1.66	$0.80	$0.64	$1.37	$0.54	$0.60	$0.80	$0.54
Diluted:								
Continuing operations	$0.57	$0.53	$0.45	($0.14)	$0.22	$0.34	$0.56	$0.20
Discontinued operations [a]	$1.08	$0.27	$0.19	$1.51	$0.32	$0.26	$0.24	$0.34
Net income	$1.65	$0.80	$0.64	$1.37	$0.54	$0.60	$0.80	$0.54
Dividends paid per share	$0.19	$0.19	$0.21	$0.21	$0.17	$0.17	$0.19	$0.19

[a] We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014. The Angola assets and Norway business 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; and Other International ("Other Int'l"), which includes the U.K. and the Kurdistan Region of Iraq. We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014, and both are shown as discontinued operations ("Disc Ops") in all periods.

Estimated Quantities of Proved Oil and Gas Reserves

The estimation of net recoverable quantities of crude oil and condensate, natural gas liquids, natural gas and synthetic crude oil is a highly technical process which is based upon several underlying assumptions that are subject to change. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Critical Accounting Estimates – Estimated Quantities of Net Reserves. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1. Business – Reserves.

Our December 31, 2014 proved reserves were calculated using the unweighted average of closing prices for the first day of each month in 2014 within the 12-month period. The 2014 unweighted averages for certain of the benchmark prices were as follows:

- WTI crude oil - $94.99 per bbl
- Henry Hub natural gas - $4.31 per mmbtu
- Brent crude oil - $101.39 per bbl

When determining the December 31, 2014 proved reserves for each property, the benchmark prices listed above were adjusted with price differentials that account for property-specific quality and location differences. Beginning in the second half of 2014, the crude oil benchmarks began to decline and this decline continued into early 2015. In addition, the Henry Hub natural gas benchmark began to decline in late 2014 and continued its decline into 2015. Commodity prices are likely to remain volatile based on global supply and demand and could decline further. The January 2015 benchmark closing prices for the first day of the month were WTI crude oil of $52.69 per bbl, Henry Hub natural gas of $2.99 per mmbtu and Brent crude oil of $55.55 per bbl. Sustained reduced commodity prices could have a material effect on the quantity and future cash flows of our proved reserves. To the extent that we experience a sustained period of reduced commodity prices in 2015, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Estimates of future cash flows associated with proved reserves are based on actual costs of developing and producing the reserves as of the end of the year. The decline in commodity prices experienced in the second half of 2014 has resulted in a reduction in the costs of developing and producing reserves. The impact of sustained reduced commodity prices on future cash flows will be partially offset by the impact of lower costs.

A sustained period of lower commodity prices could also cause us to decrease our near term capital programs and defer investment until prices improve. A shifting of capital expenditures into future periods outside of five years from the initial proved reserve booking could potentially lead to a reduction in proved undeveloped reserves. See Item 1A. Risk Factors for a further discussion of how a substantial extended decline in commodity prices could impact us.

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	Canada	E.G.[(a)]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Crude oil and condensate								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	236	—	77	222	25	560	89	649
Revisions of previous estimates	7	—	4	(5)	5	11	23	34
Improved recovery	2	—	—	—	—	2	—	2
Purchases of reserves in place	37	—	—	—	—	37	—	37
Extensions, discoveries and other additions	140	—	—	7	—	147	—	147
Production	(35)	—	(9)	(15)	(6)	(65)	(30)	(95)
End of year - 2012	387	—	72	209	24	692	82	774
Revisions of previous estimates	33	—	(1)	12	6	50	19	69
Improved recovery	—	—	—	—	—	—	11	11
Purchases of reserves in place	12	—	—	—	—	12	—	12
Extensions, discoveries and other additions	112	—	1	3	—	116	8	124
Production	(46)	—	(8)	(9)	(5)	(68)	(29)	(97)
Sales of reserves in place	(1)	—	—	—	—	(1)	—	(1)
End of year - 2013	497	—	64	215	25	801	91	892
Revisions of previous estimates	36	—	(1)	(4)	1	32	10	42
Improved recovery	2	—	—	—	—	2	—	2
Purchases of reserves in place	6	—	—	—	—	6	—	6
Extensions, discoveries and other additions	153	—	1	—	7	161	3	164
Production	(57)	—	(7)	(3)	(4)	(71)	(17)	(88)
Sales of reserves in place	(3)	—	—	—	—	(3)	(87)	(90)
End of year - 2014	634	—	57	208	29	928	—	928
Proved developed reserves:								
Beginning of year - 2012	128	—	52	179	20	379	64	443
End of year - 2012	169	—	45	168	20	402	63	465
End of year - 2013	241	—	37	176	19	473	77	550
End of year - 2014	294	—	30	175	19	518	—	518
Proved undeveloped reserves:								
Beginning of year - 2012	108	—	25	43	5	181	25	206
End of year - 2012	218	—	27	41	4	290	19	309
End of year - 2013	256	—	27	39	6	328	14	342
End of year - 2014	340	—	27	33	10	410	—	410

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	Canada	E.G.[a]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Natural gas liquids								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	43	—	40	—	1	84	—	84
Revisions of previous estimates	2	—	2	—	—	4	—	4
Purchases of reserves in place	15	—	—	—	—	15	—	15
Extensions, discoveries and other additions	32	—	—	—	—	32	—	32
Production	(4)	—	(4)	—	—	(8)	—	(8)
End of year - 2012	88	—	38	—	1	127	—	127
Revisions of previous estimates	13	—	—	—	—	13	—	13
Purchases of reserves in place	2	—	—	—	—	2	—	2
Extensions, discoveries and other additions	25	—	—	—	—	25	—	25
Production	(9)	—	(4)	—	—	(13)	—	(13)
End of year - 2013	119	—	34	—	1	154	—	154
Revisions of previous estimates	4	—	—	—	—	4	—	4
Purchases of reserves in place	1	—	—	—	—	1	—	1
Extensions, discoveries and other additions	48	—	—	—	—	48	—	48
Production	(11)	—	(4)	—	—	(15)	—	(15)
Sales of reserves in place	—	—	—	—	—	—	—	—
End of year - 2014	161	—	30	—	1	192	—	192
Proved developed reserves:								
Beginning of year - 2012	13	—	26	—	—	39	—	39
End of year - 2012	29	—	23	—	1	53	—	53
End of year - 2013	51	—	18	—	1	70	—	70
End of year - 2014	68	—	15	—	—	83	—	83
Proved undeveloped reserves:								
Beginning of year - 2012	30	—	14	—	1	45	—	45
End of year - 2012	59	—	15	—	—	74	—	74
End of year - 2013	68	—	16	—	—	84	—	84
End of year - 2014	93	—	15	—	1	109	—	109

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(bcf)	U.S.	Canada	E.G.[a]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Natural gas								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	872	—	1,571	104	21	2,568	98	2,666
Revisions of previous estimates	(29)	—	10	(1)	5	(15)	10	(5)
Purchases of reserves in place	105	—	—	—	—	105	—	105
Extensions, discoveries and other additions	224	—	—	111	—	335	—	335
Production[b]	(129)	—	(157)	(5)	(12)	(303)	(19)	(322)
End of year - 2012	1,043	—	1,424	209	14	2,690	89	2,779
Revisions of previous estimates	(4)	—	45	4	23	68	20	88
Purchases of reserves in place	13	—	3	—	—	16	—	16
Extensions, discoveries and other additions	163	—	9	—	—	172	3	175
Production[b]	(114)	—	(161)	(8)	(9)	(292)	(19)	(311)
Sales of reserves in place	(76)	—	—	—	—	(76)	—	(76)
End of year - 2013	1,025	—	1,320	205	28	2,578	93	2,671
Revisions of previous estimates	(24)	—	1	5	2	(16)	7	(9)
Purchases of reserves in place	5	—	—	—	—	5	—	5
Extensions, discoveries and other additions	290	—	44	—	—	334	2	336
Production[b]	(113)	—	(160)	(1)	(8)	(282)	(13)	(295)
Sales of reserves in place	(39)	—	—	—	—	(39)	(89)	(128)
End of year - 2014	1,144	—	1,205	209	22	2,580	—	2,580
Proved developed reserves:								
Beginning of year - 2012	551	—	1,104	104	16	1,775	24	1,799
End of year - 2012	546	—	980	99	8	1,633	20	1,653
End of year - 2013	540	—	823	95	21	1,479	20	1,499
End of year - 2014	575	—	664	94	17	1,350	—	1,350
Proved undeveloped reserves:								
Beginning of year - 2012	321	—	467	—	5	793	74	867
End of year - 2012	497	—	444	110	6	1,057	69	1,126
End of year - 2013	485	—	497	110	7	1,099	73	1,172
End of year - 2014	569	—	541	115	5	1,230	—	1,230

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	Canada	E.G.[(a)]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Synthetic crude oil								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	—	623	—	—	—	623	—	623
Revisions of previous estimates	—	45	—	—	—	45	—	45
Production	—	(15)	—	—	—	(15)	—	(15)
End of year - 2012	—	653	—	—	—	653	—	653
Revisions of previous estimates	—	36	—	—	—	36	—	36
Extensions, discoveries and other additions	—	6	—	—	—	6	—	6
Production	—	(15)	—	—	—	(15)	—	(15)
End of year - 2013	—	680	—	—	—	680	—	680
Revisions of previous estimates	—	(55)	—	—	—	(55)	—	(55)
Purchases of reserves in place	—	38	—	—	—	38	—	38
Production	—	(15)	—	—	—	(15)	—	(15)
End of year - 2014	—	648	—	—	—	648	—	648
Proved developed reserves:								
Beginning of year - 2012	—	623	—	—	—	623	—	623
End of year - 2012	—	653	—	—	—	653	—	653
End of year - 2013	—	674	—	—	—	674	—	674
End of year - 2014	—	644	—	—	—	644	—	644
Proved undeveloped reserves:								
End of year - 2013	—	6	—	—	—	6	—	6
End of year - 2014	—	4	—	—	—	4	—	4

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmboe)	U.S.	Canada	E.G.[a]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Total Proved Reserves								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	424	623	379	239	29	1,694	106	1,800
Revisions of previous estimates	5	45	7	(5)	6	58	24	82
Improved recovery	2	—	—	—	—	2	—	2
Purchases of reserves in place	70	—	—	—	—	70	—	70
Extensions, discoveries and other additions	209	—	—	26	—	235	—	235
Production[b]	(61)	(15)	(39)	(16)	(8)	(139)	(33)	(172)
End of year - 2012	649	653	347	244	27	1,920	97	2,017
Revisions of previous estimates	45	36	7	12	11	111	21	132
Improved recovery	—	—	—	—	—	—	11	11
Purchases of reserves in place	16	—	1	—	—	17	—	17
Extensions, discoveries and other additions	164	6	2	3	—	175	9	— 184
Production[b]	(74)	(15)	(39)	(10)	(7)	(145)	(32)	(177)
Sales of reserves in place	(13)	—	—	—	—	(13)	—	(13)
End of year - 2013	787	680	318	249	31	2,065	106	2,171
Revisions of previous estimates	36	(55)	—	(3)	—	(22)	11	(11)
Improved recovery	2	—	—	—	—	2	—	2
Purchases of reserves in place	8	38	—	—	—	46	—	46
Extensions, discoveries and other additions	250	—	8	—	7	265	3	— 268
Production[b]	(87)	(15)	(38)	(3)	(5)	(148)	(19)	(167)
Sales of reserves in place	(10)	—	—	—	—	(10)	(101)	(111)
End of year - 2014	986	648	288	243	33	2,198	—	2,198
Proved developed reserves:								
Beginning of year - 2012	233	623	262	196	23	1,337	68	1,405
End of year - 2012	289	653	231	185	22	1,380	66	1,446
End of year - 2013	382	674	193	192	23	1,464	80	1,544
End of year - 2014	458	644	155	191	22	1,470	—	1,470
Proved undeveloped reserves:								
Beginning of year - 2012	191	—	117	43	6	357	38	395
End of year - 2012	360	—	116	59	5	540	31	571
End of year - 2013	405	6	125	57	8	601	26	627
End of year - 2014	528	4	133	52	11	728	—	728

(a) Consists of estimated reserves from properties governed by production sharing contracts.
(b) Excludes the resale of purchased natural gas used in reservoir management.

The U.S. made the largest contribution to 2012 proved reserves increases, including 70 mmboe in purchases of reserves in place due to acquisitions in the Eagle Ford and 209 mmboe in extensions, discoveries and additions due to drilling programs within our shale plays. In addition, we added 45 mmboe in revisions of previous estimates in Canada due to technical analyses and a royalty change related to lower price realizations.

U.S. proved reserves increases in 2013 from extensions, discoveries and additions of 164 mmboe and revisions of previous estimates of 45 mmboe were the result of drilling programs in our shale plays. Revisions of previous estimates increased 36 mmboe in Canada primarily due to price and cost changes.

U.S. proved reserves increases in 2014 from extensions, discoveries and additions of 250 mmboe were the result of development activity in our U.S. resource plays. The sales of reserves in place related to our Norway and Angola discontinued operations were the largest decreases in 2014 proved reserves. The negative 55 mmboe revision to Canadian synthetic crude oil reserves primarily reflects the impact of technical and price changes on calculated royalty volumes as well as development plan changes in the mineable areas.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

	Year Ended December 31,					
(In millions)	U.S.	Canada	E.G.	Other Africa [(a)]	Other Int'l [(b)]	Total
2014 Capitalized Costs:						
Proved properties	$ 28,334	$ 9,481	$ 1,804	$ 823	$ 5,707	$ 46,149
Unproved properties	1,861	1,505	64	460	237	4,127
Total	30,195	10,986	1,868	1,283	5,944	50,276
Accumulated depreciation, depletion and amortization:						
Proved properties	13,746	1,183	1,010	260	5,075	21,274
Unproved properties	189	1	—	—	9	199
Total	13,935	1,184	1,010	260	5,084	21,473
Net capitalized costs	$ 16,260	$ 9,802	$ 858	$ 1,023	$ 860	$ 28,803
2013 Capitalized Costs:						
Proved properties	$ 24,165	$ 9,276	$ 1,683	$ 2,257	$ 8,898	$ 46,279
Unproved properties	2,097	1,508	31	693	510	4,839
Total	26,262	10,784	1,714	2,950	9,408	51,118
Accumulated depreciation, depletion and amortization:						
Proved properties	11,568	989	918	307	7,607	21,389
Unproved properties	180	1	—	13	15	209
Total	11,748	990	918	320	7,622	21,598
Net capitalized costs	$ 14,514	$ 9,794	$ 796	$ 2,630	$ 1,786	$ 29,520

(a) 2013 balances include capitalized costs related to Angola.
(b) 2013 balances include capitalized costs related to Norway.

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

(In millions)	U.S.	Canada	E.G.	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
December 31, 2014								
Property acquisition:								
Proved	$ 26	$ —	$ —	$ —	$ —	$ 26	$ —	$ 26
Unproved	202	3	—	53	2	260	1	261
Exploration	1,140	4	35	119	119	1,417	6	1,423
Development	3,532	196	139	16	94	3,977	418	4,395
Total	$ 4,900	$ 203	$ 174	$ 188	$ 215	$ 5,680	$ 425	$ 6,105
December 31, 2013								
Property acquisition:								
Proved	$ 51	$ 30	$ 9	$ —	$ —	$ 90	$ —	$ 90
Unproved	157	—	—	44	21	222	—	222
Exploration	885	9	4	124	151	1,173	98	1,271
Development	2,876	280	84	46	83	3,369	499	3,868
Total	$ 3,969	$ 319	$ 97	$ 214	$ 255	$ 4,854	$ 597	$ 5,451
December 31, 2012								
Property acquisition:								
Proved	$ 756	$ —	$ —	$ —	$ 3	$ 759	$ —	$ 759
Unproved	432	—	18	63	(13)	500	5	505
Exploration	1,587	31	3	25	165	1,811	45	1,856
Development	2,469	195	22	15	164	2,865	662	3,527
Total	$ 5,244	$ 226	$ 43	$ 103	$ 319	$ 5,935	$ 712	$ 6,647

(a) Includes costs incurred whether capitalized or expensed.

Results of Operations for Oil and Gas Producing Activities

	U.S.	Canada	E.G.	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Year Ended December 31, 2014								
Revenues and other income:								
Sales	$ 5,754	$ 1,316	$ 43	$ 244	$ 440	$ 7,797	$ 189	$ 7,986
Transfers	3	—	588	—	3	594	1,848	2,442
Other income[(a)]	(85)	—	—	—	—	(85)	1,832	1,747
Total revenues and other income	5,672	1,316	631	244	443	8,306	3,869	12,175
Expenses:								
Production costs	(1,544)	(803)	(154)	(79)	(253)	(2,833)	(181)	(3,014)
Exploration expenses	(607)	(1)	(26)	(103)	(56)	(793)	(5)	(798)
Depreciation, depletion and amortization[(b)]	(2,474)	(206)	(93)	(9)	(115)	(2,897)	(105)	(3,002)
Technical support and other	(193)	(15)	(31)	(21)	(14)	(274)	(7)	(281)
Total expenses	(4,818)	(1,025)	(304)	(212)	(438)	(6,797)	(298)	(7,095)
Results before income taxes	854	291	327	32	5	1,509	3,571	5,080
Income tax provision	(302)	(71)	(117)	(32)	(18)	(540)	(1,496)	(2,036)
Results of operations	$ 552	$ 220	$ 210	$ —	$ (13)	$ 969	$ 2,075	$ 3,044
Year Ended December 31, 2013								
Revenues and other income:								
Sales	$ 5,059	$ 1,376	$ 33	$ 1,106	$ 687	$ 8,261	$ 599	$ 8,860
Transfers	3	—	715	—	6	724	2,935	3,659
Other income[(a)]	(9)	—	—	—	(8)	(17)	—	(17)
Total revenues and other income	5,053	1,376	748	1,106	685	8,968	3,534	12,502
Expenses:								—
Production costs	(1,318)	(867)	(113)	(73)	(271)	(2,642)	(273)	(2,915)
Exploration expenses	(717)	(8)	(3)	(65)	(98)	(891)	(107)	(998)
Depreciation, depletion and amortization[(b)]	(1,980)	(218)	(97)	(28)	(151)	(2,474)	(345)	(2,819)
Technical support and other	(185)	(21)	(30)	(19)	(15)	(270)	(38)	(308)
Total expenses	(4,200)	(1,114)	(243)	(185)	(535)	(6,277)	(763)	(7,040)
Results before income taxes	853	262	505	921	150	2,691	2,771	5,462
Income tax provision	(323)	(66)	(182)	(920)	(117)	(1,608)	(1,948)	(3,556)
Results of operations	$ 530	$ 196	$ 323	$ 1	$ 33	$ 1,083	$ 823	$ 1,906
Year Ended December 31, 2012								
Revenues and other income:								
Sales	$ 3,879	$ 1,261	$ 29	$ 2,000	$ 738	$ 7,907	$ 97	$ 8,004
Transfers	2	—	818	—	—	820	3,601	4,421
Other income[(a)]	(8)	—	—	—	(32)	(40)	—	(40)
Total revenues and other income	3,873	1,261	847	2,000	706	8,687	3,698	12,385
Expenses:								—
Production costs	(1,054)	(826)	(141)	(58)	(222)	(2,301)	(188)	(2,489)
Exploration expenses	(558)	(30)	(5)	(10)	(82)	(685)	(27)	(712)
Depreciation, depletion and amortization[(b)]	(1,792)	(217)	(95)	(43)	(147)	(2,294)	(470)	— (2,764)
Technical support and other	(193)	(8)	(5)	(4)	(23)	(233)	(26)	(259)
Total expenses	(3,597)	(1,081)	(246)	(115)	(474)	(5,513)	(711)	(6,224)
Results before income taxes	276	180	601	1,885	232	3,174	2,987	6,161
Income tax provision	(100)	(45)	(210)	(1,795)	(189)	(2,339)	(2,260)	(4,599)
Results of operations	$ 176	$ 135	$ 391	$ 90	$ 43	$ 835	$ 727	$ 1,562

(a) Includes net gain (loss) on dispositions.
(b) Includes long-lived asset impairments.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

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

	Year Ended December 31,		
(In millions)	2014	2013	2012
Results of operations	$ 3,044	$ 1,906	$ 1,562
Discontinued operations	(2,075)	(823)	(727)
Results of continuing operations	969	1,083	835
Items not included in results of oil and gas operations, net of tax:			
Marketing income and other non-oil and gas producing related activities	73	40	42
Income from equity method investments	327	340	309
Items not allocated to segment income, net of tax:			
Loss on asset dispositions	58	20	31
Long-lived asset impairments	69	10	231
Segment income	$ 1,496	$ 1,493	$ 1,448

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

U.S. GAAP prescribes guidelines for computing the standardized measure of future net cash flows and changes therein relating to estimated proved reserves, giving very specific assumptions to be made such as the use of a 10 percent discount rate and an unweighted average of commodity prices in the prior 12-month period using the closing prices on the first day of each month. These and other required assumptions have not always proved accurate in the past, and other valid assumptions would give rise to substantially different results. This information is not the fair value nor does it represent the expected present value of future cash flows of our crude oil and condensate, natural gas liquid, natural gas and synthetic crude oil reserves.

(In millions)	U.S.	Canada	E.G.	Other Africa	Other Int'l	Total
Year Ended December 31, 2014						
Future cash inflows	$ 66,307	$ 55,675	$ 5,027	$ 23,803	$ 3,040	$ 153,852
Future production and support costs	(19,504)	(34,838)	(1,270)	(803)	(1,452)	(57,867)
Future development costs	(14,626)	(9,754)	(259)	(680)	(1,669)	(26,988)
Future income tax expenses	(8,124)	(2,190)	(922)	(21,008)	(9)	(32,253)
Future net cash flows	$ 24,053	$ 8,893	$ 2,576	$ 1,312	$ (90) [a]	$ 36,744
10 percent annual discount for timing of cash flows	(12,138)	(6,613)	(915)	(742)	221	(20,187)
Standardized measure of discounted future net cash flows-						
-related to continuing operations	$ 11,915	$ 2,280	$ 1,661	$ 570	$ 131	$ 16,557
-related to discontinued operations	$ —	$ —	$ —	$ —	—	—
Year Ended December 31, 2013						
Future cash inflows	$ 54,099	$ 59,585	$ 5,911	$ 28,195	$ 3,178	$ 150,968
Future production and support costs	(16,774)	(35,954)	(1,619)	(976)	(1,191)	(56,514)
Future development costs	(9,685)	(9,694)	(367)	(793)	(1,302)	(21,841)
Future income tax expenses	(7,592)	(3,098)	(1,032)	(24,982)	(643)	(37,347)
Future net cash flows	$ 20,048	$ 10,839	$ 2,893	$ 1,444	$ 42	$ 35,266
10 percent annual discount for timing of cash flows	(9,940)	(8,300)	(1,084)	(828)	128	(20,024)
Standardized measure of discounted future net cash flows-						
-related to continuing operations	$ 10,108	$ 2,539	$ 1,809	$ 616	$ 170	$ 15,242
-related to discontinued operations	$ —	$ —	$ —	$ 1,302	$ 1,228	$ 2,530
Year Ended December 31, 2012						
Future cash inflows	$ 42,710	$ 55,171	$ 6,627	$ 28,173	$ 2,897	$ 135,578
Future production and support costs	(13,765)	(32,131)	(1,829)	(1,015)	(784)	(49,524)
Future development costs	(11,104)	(9,350)	(451)	(787)	(1,139)	(22,831)
Future income tax expenses	(4,489)	(2,948)	(1,191)	(25,020)	(827)	(34,475)
Future net cash flows	$ 13,352	$ 10,742	$ 3,156	$ 1,351	$ 147	$ 28,748
10 percent annual discount for timing of cash flows	(6,956)	(7,842)	(1,178)	(743)	59	(16,660)
Standardized measure of discounted future net cash flows-						
-related to continuing operations	$ 6,396	$ 2,900	$ 1,978	$ 608	$ 206	$ 12,088
-related to discontinued operations	$ —	$ —	$ —	$ 642	$ 1,489	$ 2,131

[a] Future cash flows for Other International reflects the impact of future abandonment costs related to the U.K.

Changes in the Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
(In millions)	2014	2013	2012
Sales and transfers of oil and gas produced, net of production and support costs	$ (5,284)	$ (6,080)	$ (9,696)
Net changes in prices and production and support costs related to future production	(2,688) [b]	(336)	457
Extensions, discoveries and improved recovery, less related costs	3,539	3,415	2,763
Development costs incurred during the period	4,088	3,429	3,197
Changes in estimated future development costs	(1,423)	898	(135)
Revisions of previous quantity estimates[a]	(3,193) [c]	1,330	508
Net changes in purchases and sales of minerals in place	(168)	(229)	933
Accretion of discount	3,132	2,657	2,640
Net change in income taxes	3,312	(1,930)	12
Net change for the year	1,315	3,154	679
Beginning of the year related to continuing operations	15,242	12,088	11,409
End of the year related to continuing operations	$ 16,557	$ 15,242	$ 12,088
Net change for the year related to discontinued operations	$ (2,530)	$ 399	$ (242)

[a] Includes amounts resulting from changes in the timing of production.
[b] Decrease primarily due to lower realized prices related to Other Africa and Other International.
[c] Decrease mostly due to royalty adjustments on Canadian synthetic crude oil.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Year Ended December 31,		
(In millions)	2014	2013	2012
Segment Income			
North America E&P	$ 693	$ 529	$ 382
International E&P	568	758	895
Oil Sands Mining	235	206	171
Segment income	1,496	1,493	1,448
Items not allocated to segments, net of income taxes	(527)	(562)	(592)
Income from continuing operations	969	931	856
Discontinued operations[a]	2,077	822	726
Net income	$ 3,046	$ 1,753	$ 1,582
Capital Expenditures[b]			
North America E&P	$ 4,698	$ 3,649	$ 3,988
International E&P	534	456	235
Oil Sands Mining	212	286	188
Corporate	51	58	115
Discontinued operations[a]	390	535	605
Total	$ 5,885	$ 4,984	$ 5,131
Exploration Expenses			
North America E&P	$ 608	$ 725	$ 588
International E&P	185	166	97
Total	$ 793	$ 891	$ 685

(a) We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014. The Angola assets and Norway business are reflected as discontinued operations in all periods presented.

(b) Capital expenditures include accruals.

Net Sales Volumes	2014	2013	2012
North America E&P			
Crude Oil and Condensate *(mbbld)*			
Bakken	45	35	27
Eagle Ford	72	51	23
Oklahoma Resource Basins	3	2	1
Other North America[(c)]	37	38	45
Total Crude Oil and Condensate	157	126	96
Natural Gas Liquids *(mbbld)*			
Bakken	3	2	1
Eagle Ford	19	14	5
Oklahoma Resource Basins	5	4	2
Other North America[(c)]	2	3	3
Total Natural Gas Liquids	29	23	11
Total Liquid Hydrocarbons *(mbbld)*			
Bakken	48	37	28
Eagle Ford	91	65	28
Oklahoma Resource Basins	8	6	3
Other North America[(c)]	39	41	48
Total Liquid Hydrocarbons	186	149	107
Natural Gas *(mmcfd)*			
Bakken	18	13	8
Eagle Ford	123	94	37
Oklahoma Resource Basins	61	48	32
Other North America[(c)]	108	157	281
Total Natural Gas	310	312	358
Equivalent Barrels *(mboed)*			
Bakken	51	39	29
Eagle Ford	112	81	34
Oklahoma Resource Basins	18	14	8
Other North America[(c)]	57	67	95
Total North America E&P *(mboed)*	238	201	166

(c) Includes Gulf of Mexico and other conventional onshore U.S. production, plus Alaska in 2013 and 2012.

Net Sales Volumes	2014	2013	2012
International E&P			
Crude Oil and Condensate *(mbbld)*			
Equatorial Guinea	21	23	25
United Kingdom	11	14	15
Libya	7	24	42
Total Crude Oil and Condensate	39	61	82
Natural Gas Liquids *(mbbld)*			
Equatorial Guinea	10	11	11
United Kingdom	—	1	1
Total Natural Gas Liquids	10	12	12
Total Liquid Hydrocarbons *(mbbld)*			
Equatorial Guinea	31	34	36
United Kingdom	11	15	16
Libya	7	24	42
Total Liquid Hydrocarbons	49	73	94
Natural Gas *(mmcfd)*			
Equatorial Guinea	439	442	428
United Kingdom[(d)]	28	32	48
Libya	1	22	15
Total Natural Gas	468	496	491
Equivalent Barrels *(mboed)*			
Equatorial Guinea	104	107	107
United Kingdom[(d)]	16	20	24
Libya	7	28	45
Total International E&P *(mboed)*	127	155	176
Oil Sands Mining			
Synthetic Crude Oil *(mbbld)*[(e)]	50	48	47
Total Continuing Operations *(mboed)*	415	404	389
Discontinued Operations - Angola *(mboed)*[(a)]	2	10	—
Discontinued Operations - Norway *(mboed)*[(a)]	52	79	90
Total Company *(mboed)*	469	493	479
Net Sales Volumes of Equity Method Investees			
LNG *(mtd)*	6,535	6,548	6,290
Methanol *(mtd)*	1,092	1,249	1,298

(d) Includes natural gas acquired for injection and subsequent resale of 6 mmcfd, 7 mmcfd and 15 mmcfd for 2014, 2013, and 2012.
(e) Includes blendstocks.

Average Price Realizations (f)	2014	2013	2012
North America E&P			
Crude Oil and Condensate *(per bbl)*			
Bakken	$81.63	$90.25	$83.11
Eagle Ford	87.99	99.69	100.14
Oklahoma Resource Basins	87.15	94.84	89.26
Other North America *(c)*	84.21	90.42	91.75
Total Crude Oil and Condensate	85.25	94.19	91.30
Natural Gas Liquids *(per bbl)*			
Bakken	$43.25	$41.60	$42.35
Eagle Ford	29.60	30.16	32.96
Oklahoma Resource Basins	32.61	35.28	31.82
Other North America *(c)*	51.12	55.69	52.51
Total Natural Gas Liquids	33.42	35.12	39.57
Total Liquid Hydrocarbons *(per bbl)* *(f)*			
Bakken	$79.41	$87.76	$81.36
Eagle Ford	75.83	84.95	88.09
Oklahoma Resource Basins	50.86	50.77	49.21
Other North America *(c)*	81.88	88.16	89.03
Total Liquid Hydrocarbons	77.02	85.20	85.80
Natural Gas *(per mcf)*			
Bakken	$5.28	$3.90	$3.11
Eagle Ford	4.43	3.67	3.03
Oklahoma Resource Basins	4.49	3.78	3.05
Other North America *(c)*	4.65	3.95	4.20
Total Natural Gas	4.57	3.84	3.92

(f) Excludes gains or losses on derivative instruments. Inclusion of realized gains (losses) on crude oil derivative instruments would have increased (decreased) average liquid hydrocarbon price realizations per barrel by $(0.27) and $0.40 for 2013 and 2012. There were no crude oil derivative instruments for 2014.

Average Price Realizations	2014	2013	2012
International E&P			
Crude Oil and Condensate *(per bbl)*			
Equatorial Guinea	$81.01	$90.62	$92.56
United Kingdom	94.31	110.76	109.50
Libya	94.70	122.92	127.31
Other International	—	—	—
Total Crude Oil and Condensate	87.23	108.18	113.61
Natural Gas Liquids *(per bbl)*			
Equatorial Guinea[g]	$1.00	$1.00	$1.00
United Kingdom	67.73	72.14	78.81
Libya	—	—	—
Other International	—	—	—
Total Natural Gas Liquids	2.46	5.24	8.32
Total Liquid Hydrocarbons *(per bbl)*			
Equatorial Guinea	$54.29	$60.34	$64.33
United Kingdom	93.75	108.92	107.31
Libya	94.70	122.92	127.31
Other International	—	—	—
Total Liquid Hydrocarbons	68.98	91.04	100.02
Natural Gas *(per mcf)*			
Equatorial Guinea[g]	$0.24	$0.24	$0.24
United Kingdom	8.27	10.64	9.72
Libya	3.11	5.44	5.76
Other International	—	—	—
Total Natural Gas	0.72	1.15	1.33
Oil Sands Mining			
Synthetic Crude Oil *(per bbl)*	$83.35	$87.51	$81.72
Discontinued Operations - Angola *(per boe)*[a]	99.82	104.77	—
Discontinued Operations - Norway *(per boe)*[a]	104.22	109.60	111.82
Total Proved Reserves (at year end)			
Crude Oil and Condensate *(mmbbl)*			
North America E&P	634	497	387
International E&P	294	304	305
Total Crude Oil and Condensate	928	801	692
Natural Gas Liquids *(mmbbl)*			
North America E&P	161	119	88
International E&P	31	35	39
Total Natural Gas Liquids	192	154	127
Natural Gas *(bcf)*			
North America E&P	1,144	1,025	1,043
International E&P	1,436	1,553	1,647
Total Natural Gas	2,580	2,578	2,690
Synthetic Crude Oil *(mmbbl)*			
Oil Sands Mining	648	680	653
Total Continuing Operations *(mmboe)*	2,198	2,065	1,920
Discontinued Operations *(mmboe)*[a]	—	106	97
Total Proved Reserves *(mmboe)*	2,198	2,171	2,017

(g) 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.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this Report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective as of December 31, 2014.

Management's Annual Report on Internal Control Over Financial Reporting

See "Management’s Report on Internal Control over Financial Reporting" under Item 8 of this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

See "Report of Independent Registered Public Accounting Firm" under Item 8 of this Form 10-K.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2014, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item is incorporated by reference to "Election of Directors," "Corporate Governance—Committees of the Board" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement for the 2015 Annual Meeting of Stockholders, to be filed with the SEC within 120 days of December 31, 2014 (the "2015 Proxy Statement").

See "Executive Officers of the Registrant" under Item 1 of this Form 10-K for information about our executive officers.

Our Code of Business Conduct and the Code of Ethics for Senior Financial Officers are available on our website at www.marathonoil.com.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "Compensation Committee Report," "Director Compensation," "Compensation Discussion and Analysis" and "Executive Compensation" in the 2015 Proxy Statement.

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

Portions of information required by this item are incorporated by reference to "Security Ownership of Certain Beneficial Owners and Management" in the 2015 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2014 with respect to shares of Marathon Oil common stock that may be issued under our existing equity compensation plans:

- Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan")
- Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") – No additional awards will be granted under this plan.
- Marathon Oil Corporation 2003 Incentive Compensation Plan (the "2003 Plan") – No additional awards will be granted under this plan.
- Deferred Compensation Plan for Non-Employee Directors – No additional awards will be granted under this plan.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights[(c)]	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by stockholders	14,453,729 [(a)]	$29.68	45,489,820 [(d)]
Equity compensation plans not approved by stockholders	20,984 [(b)]	N/A	—
Total	14,474,713	N/A	45,489,820

(a) Includes the following:

- 3,237,349 stock options outstanding under the 2012 Plan; 9,106,352 stock options outstanding under the 2007 Plan; 1,084,135 stock options outstanding under the 2003 Plan;
- 355,709 common stock units that have been credited to non-employee directors pursuant to the non-employee director deferred compensation program and the annual director stock award program established under the 2012 Plan, 2007 Plan and 2003 Plan; common stock units credited under the 2012 Plan, 2007 Plan and 2003 Plan were 82,233, 222,215 and 51,261, respectively;
- 670,184 restricted stock units granted to non-officers under the 2012 Plan and 2007 Plan and outstanding as of December 31, 2014.

In addition to the awards reported above 200,444 and 2,577,725 shares of restricted stock were issued and outstanding as of December 31, 2014, but subject to forfeiture restrictions under the 2007 Plan and 2012 Plan, respectively.

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

(c) The weighted-average exercise prices do not take the restricted stock units or common stock units into account as these awards have no exercise price.

(d) Reflects the shares available for issuance under the 2012 Plan. No more than 18,949,438 of these shares may be issued for awards other than stock options or stock appreciation rights. In addition, shares related to grants that are forfeited, terminated, canceled or expire unexercised shall again immediately become available for issuance.

The Deferred Compensation Plan for Non-Employee Directors is our only equity compensation plan that has not been approved by our stockholders. Our authority to make equity grants under this plan was terminated effective April 30, 2003. Under the Deferred Compensation Plan for Non-Employee Directors, all non-employee directors were required to defer half of their annual retainers in the form of common stock units. On the date the retainer would have otherwise been payable to the non-employee director, we credited an unfunded bookkeeping account for each non-employee director with a number of common stock units equal to half of his or her annual retainer divided by the fair market value of our common stock on that date. The ongoing value of each common stock unit equals the market price of a share of our common stock. When the non-employee director leaves the Board, he or she is issued actual shares of our common stock equal to the number of common stock units in his or her account at that time.

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

Information required by this item is incorporated by reference to "Transactions with Related Persons," and "Corporate Governance—Director Independence" in the 2015 Proxy Statement.

Item 14. Principal Accountant Fees and Services

Information required by this item is incorporated by reference to "Ratification of Independent Auditor for 2015" in the 2015 Proxy Statement.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements – See Part II, Item 8. of this Annual Report on Form 10-K.
2. Financial Statement Schedules – Financial statement schedules required under SEC rules but not included in this Annual Report on Form 10-K are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.
3. Exhibits – The information required by this Item 15 is incorporated by reference to the Exhibit Index accompanying this Annual Report on Form 10-K.

SIGNATURES

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

March 2, 2015 MARATHON OIL CORPORATION

By: /s/ GARY E. WILSON

Gary E. Wilson

Vice President, Controller and Chief Accounting Officer

POWER OF ATTORNEY

Each person whose signature appears below appoints Lee M. Tillman, John R. Sult, and Gary E. Wilson, and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, with full power and authority to each of said attorneys-in-fact and agents to do and perform each and every act whatsoever that is necessary, appropriate or advisable in connection with any or all of the above-described matters and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on March 2, 2015 on behalf of the registrant and in the capacities indicated.

Signature	Title
/S/ LEE M. TILLMAN Lee M. Tillman	President and Chief Executive Officer and Director
/S/ JOHN R. SULT John R. Sult	Executive Vice President and Chief Financial Officer
/s/ GARY E. WILSON Gary E. Wilson	Vice President, Controller and Chief Accounting Officer
/S/ DENNIS H. REILLEY Dennis H. Reilley	Chairman of the Board
/S/ GREGORY H. BOYCE Gregory H. Boyce	Director
/S/ PIERRE BRONDEAU Pierre Brondeau	Director
/S/ CHADWICK C. DEATON Chadwick C. Deaton	Director
/S/ MARCELA E. DONADIO Marcela E. Donadio	Director
/S/ SHIRLEY ANN JACKSON Shirley Ann Jackson	Director
/S/ PHILIP LADER Philip Lader	Director
/S/ MICHAEL E. J. PHELPS Michael E. J. Phelps	Director

Exhibit Index

Exhibit Number	Exhibit Description	Incorporated by Reference		
		Form	Exhibit	Filing Date
3	**Articles of Incorporation and Bylaws**			
3.1	Restated Certificate of Incorporation of Marathon Oil Corporation	10-Q	3.1	8/8/2013
3.2	Amended By-Laws of Marathon Oil Corporation effective February 25, 2014	10-K	3.2	2/28/2014
3.3	Specimen of Common Stock Certificate	10-K	3.3	2/28/2014
4	**Instruments Defining the Rights of Security Holders, Including Indentures**			
4.1	Indenture, dated as of February 26, 2002, between Marathon Oil Corporation and The Bank of New York Trust Company, N.A., successor in interest to JPMorgan Chase Bank as Trustee, relating to senior debt securities of Marathon Oil Corporation. Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10 percent of the total consolidated assets of Marathon Oil. Marathon Oil hereby agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon its request	10-K	4.2	2/28/2014
10	**Material Contracts**			
10.1	Amended and Restated Credit Agreement, dated as of May 28, 2014, among Marathon Oil Corporation, as borrower, The Royal Bank of Scotland plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein	8-K	4.1	6/2/2014
10.2†	Marathon Oil Corporation 2012 Incentive Compensation Plan	DEF 14A	App. III	3/8/2012
10.3†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Non-Qualified Stock Option Award Agreement	8-K	10.1	8/1/2014
10.4†	Form of Performance Unit Award Agreement 2014 - 2016 Performance Cycle for Section 16 Officers	10-Q	10.1	5/7/2014
10.5†	Form of Performance Unit Award Agreement 2014 - 2016 Performance Cycle for Officers	10-Q	10.2	5/7/2014
10.6†	Form of Initial CEO Option Grant Agreement granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan	10-Q	10.1	11/6/2013
10.7†	Form of CEO Restricted Stock Agreement granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-Q	10.2	11/6/2013
10.8†	Form of CEO Restricted Stock Award Agreement granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year cliff vesting)	10-Q	10.3	11/6/2013
10.9†	Form of Performance Unit Award Agreement (2013-2015 Performance Cycle) for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan	10-Q	10.1	5/10/2013
10.10†	Form of Performance Unit Award Agreement (2013-2015 Performance Cycle) for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan	10-Q	10.2	5/10/2013
10.11†	Form of Nonqualified Stock Option Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.5	2/22/2013

Exhibit Number	Exhibit Description	Incorporated by Reference		
		Form	Exhibit	Filing Date
10.12†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.6	2/22/2013
10.13†	Form of Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year cliff vesting)	10-K	10.7	2/22/2013
10.14†	Form of Restricted Stock Award Agreement for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year cliff vesting)	10-K	10.8	2/22/2013
10.15†	Form of Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.9	2/22/2013
10.16†	Form of Restricted Stock Award Agreement for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.10	2/22/2013
10.17†	Form of Nonqualified Stock Option Award Agreement for non-officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.11	2/22/2013
10.18†	Form of Nonqualified Stock Option Award Agreement for non-officers in Canada granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.12	2/22/2013
10.19†	Form of Restricted Stock Award Agreement for non-officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.13	2/22/2013
10.20†	Form of Restricted Stock Unit Award Agreement for non-officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.14	2/22/2013
10.21†	Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.5	2/29/2012
10.22†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.6	2/29/2012
10.23†	Form of Officer Restricted Stock Award Agreement granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.8	2/29/2012
10.24†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.5	2/28/2011
10.25†	Form of Officer Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.7	2/28/2011
10.26†	Form of Performance Unit Award Agreement (2012-2014 Performance Cycle) granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan.	10-Q	10.2	5/4/2012
10.27†	Form of Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan.	10-K	10.27	2/26/2010
10.28†	Form of Nonqualified Stock Option Award Agreement granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.26	2/26/2010
10.29†	Marathon Oil Corporation 2003 Incentive Compensation Plan, Effective January 1, 2003	10-K	10.9	2/26/2010

Exhibit Number	Exhibit Description	Incorporated by Reference		
		Form	Exhibit	Filing Date
10.30†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2003 Incentive Compensation Plan	10-K	10.22	2/26/2010
10.31†	Form of Officer Restricted Stock Award Agreement granted under the Marathon Oil Corporation 2003 Incentive Compensation Plan	10-K	10.23	2/26/2010
10.32	Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors (Amended and Restated as of January 1, 2012)	10-Q	10.3	5/7/2014
10.33†	Marathon Oil Company Deferred Compensation Plan Amended and Restated Effective June 30, 2011	10-K	10.32	2/29/2012
10.34†	Marathon Oil Company Excess Benefit Plan Amended and Restated	10-K	10.31	2/29/2012
10.35†	Marathon Oil Corporation 2011 Officer Change in Control Severance Benefits Plan (For Officers Hired or Promoted after October 26, 2011)	10-Q	10.4	5/4/2012
10.36*†	Marathon Oil Corporation 2011 Officer Change in Control Severance Benefits Plan (as amended, effective November 1, 2014)			
10.37†	Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts	10-K	10.10	2/28/2011
10.38†	Marathon Oil Executive Tax, Estate, and Financial Planning Program, Amended and Restated, Effective January 1, 2009	10-K	10.32	2/27/2009
10.39†	Marathon Oil Corporation Bonus Agreement Upon Commencement of Employment for Lee M. Tillman	10-Q	10.4	11/6/2013
10.40	Tax Sharing Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Petroleum Corporation and MPC Investment LLC	8-K	10.1	5/26/2011
12.1*	Computation of Ratio of Earnings to Fixed Charges			
14.1	Code of Ethics for Senior Financial Officers	10-K	14.1	2/26/2010
21.1*	List of Significant Subsidiaries			
23.1*	Consent of Independent Registered Public Accounting Firm			
23.2*	Consent of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists			
23.3*	Consent of Ryder Scott Company, L.P., independent petroleum engineers and geologists			
23.4*	Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists			
31.1*	Certification of President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934			
31.2*	Certification of Executive Vice President and Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934			
32.1*	Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350			
32.2*	Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350			
99.1*	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2014			
99.2	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2013	10-K	99.1	2/28/2014
99.3	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2012	10-K	99.1	2/22/2013

Exhibit Number	Exhibit Description	Incorporated by Reference		
		Form	Exhibit	Filing Date
99.4*	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2014			
99.5	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2013	10-K	99.4	2/28/2014
99.6	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2012	10-K	99.4	2/22/2013
99.7*	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2014			
99.8	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2013	10-K	99.7	2/28/2014
99.9	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2012	10-K	99.6	2/22/2013
101.INS*	XBRL Instance Document			
101.SCH*	XBRL Taxonomy Extension Schema			
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase			
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase			
101.LAB*	XBRL Taxonomy Extension Label Linkbase			
101.DEF*	XBRL Taxonomy Extension Definition Linkbase			

* Filed herewith.

** Furnished, not filed.

† Management contract or compensatory plan or arrangement.

Corporate Information

Corporate Headquarters
5555 San Felipe Street
Houston, TX 77056-2723

Marathon Oil Corporation Web Site
www.marathonoil.com

Investor Relations Office
5555 San Felipe Street
Houston, TX 77056-2723

Chris C. Phillips, Director, Investor Relations
+1 713-296-3213

Zach B. Dailey, Director, Investor Relations
+1 713-296-4140

Notice of Annual Meeting
The 2015 Annual Meeting of Stockholders will be held in Houston, Texas, on April 29, 2015.

Independent Accountants
PricewaterhouseCoopers LLP
1201 Louisiana, Suite 2900
Houston, TX 77002-5678

Stock Exchange Listing
New York Stock Exchange

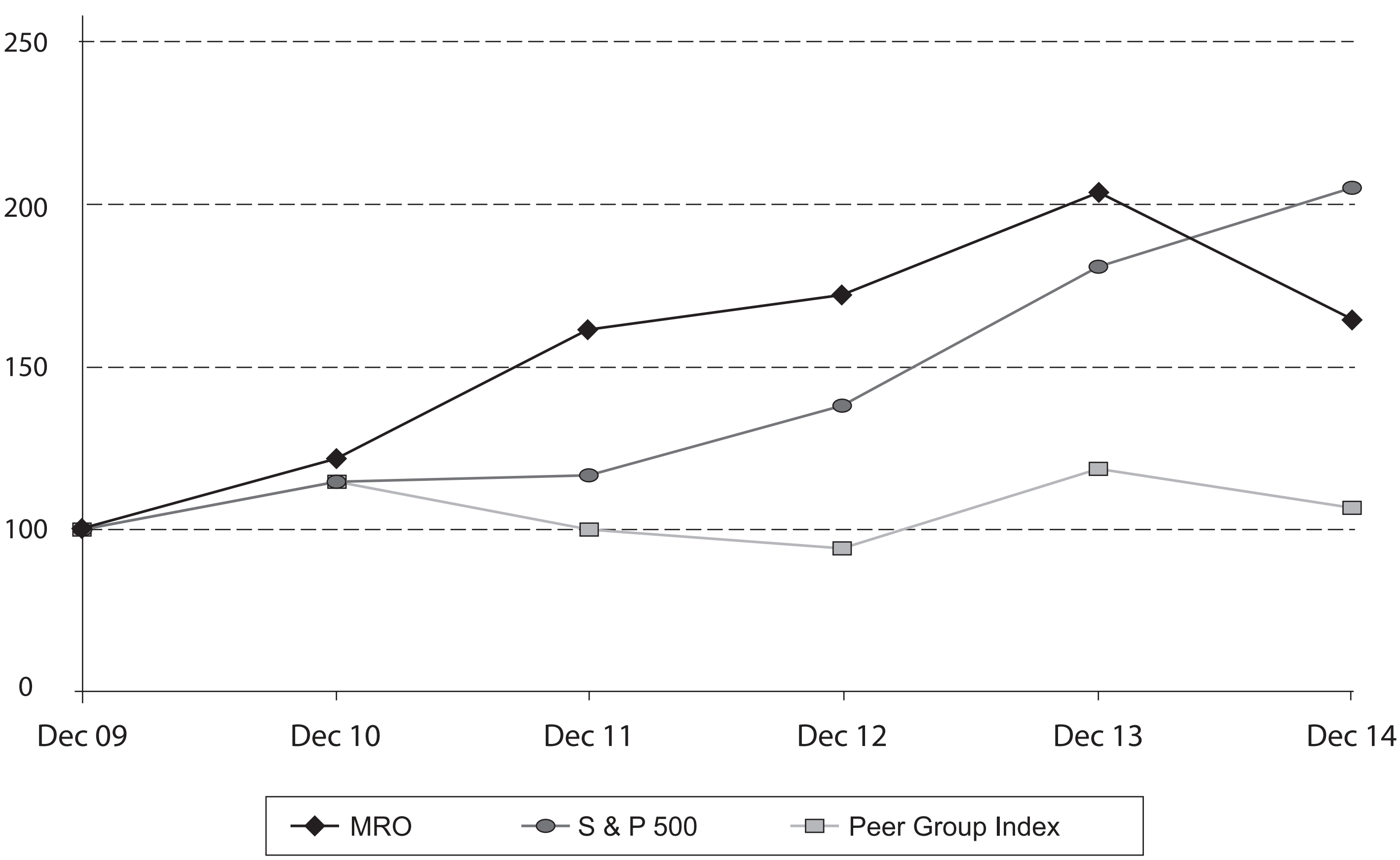
Common Stock Symbol
MRO

Stock Transfer Agent
Computershare
211 Quality Circle, Suite 210
College Station, TX 77845
888-843-5542 (Toll free - U.S., Canada, Puerto Rico)
+1 781-575-4735 (non-U.S.)
web.queries@computershare.com

Dividends
Dividends on Common Stock, as declared by the Board of Directors, are normally paid on the 10th day of March, June, September and December.

Stockholder Return Performance Graph
The line graph below compares the yearly change in cumulative total stockholder return for our common stock with the cumulative total return of the Standard & Poor's ("S&P") 500 Stock Index and our peer group index (the "Peer Group Index"). The Peer Group Index is comprised of Anadarko Petroleum Corp., Apache Corp., Chesapeake Energy Corp., Devon Energy Corp., Encana Corp., EOG Resources Inc., Hess Corp., Murphy Oil Corp., Noble Energy Inc., Occidental Petroleum Corp., and Talisman Energy.

Comparison of Cumulative Total Return on $100
Invested in Marathon Oil Common Stock on December 31, 2009
vs.
***S&P 500 and Peer Group Index**



* Total return assumes reinvestment of dividends

Cautionary Note and Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

The letter to stockholders contains 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 (the "Exchange Act"). All statements other than statements of historical fact are forward-looking statements, including without limitation statements regarding: our operational, financial and growth strategies, ability to successfully effect those strategies and the expected results therefrom; our 2015 capital, investment and exploration budget and the planned allocation thereof; planned activities, including drilling plans and projects, planned wells, rig count, inventory, seismic and exploration plans, and the expected timing and impact thereof; expectations regarding future economic and market conditions and the effects on us thereof; our financial and operational outlook, and ability to fulfill that outlook; opportunities in the current pricing environment; our financial position, liquidity and capital resources, and the benefits thereof; resource, inventory and asset quality and the expected benefits and performance thereof; 2015 production growth expectations and the drivers thereof; reserve estimates; expected contributions of our new board member; our commitment to creating long-term stockholder value; and statements related to advanced completion technologies and downspacing, and the expected benefits and results thereof.

While we believe that the assumptions concerning future events are reasonable, a number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to: conditions in the oil and gas industry, including the level of supply or demand for liquid hydrocarbons and natural gas and the impact on the price of liquid hydrocarbons and natural gas; changes in expected levels of reserves or production; changes in political or economic conditions in key operating markets, including international markets; the amount of capital available for exploration and development; 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; non-performance by third parties of their contractual obligations; unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto; cyber-attacks that adversely affect operations; changes in safety, health, environmental and other regulations; and other geological, operating and economic considerations. These forward-looking statements are also affected by the risk factors, forward-looking statements and challenges and uncertainties described in our Annual Report on Form 10-K for the year ended December 31, 2014, and those set forth from time to time in our filings with the Securities and Exchange Commission, which are currently available at www.marathonoil.com. Except as required by law, we expressly disclaim any intention or obligation to revise or update any forward-looking statements whether as a result of new information, future events or otherwise.

**Editor's note:*
2P - Most likely or "2P" volumes represent most likely deterministic estimates of proved plus probable reserves as defined by the SEC, plus contingent or "2C" volumes with the same technical certainty as proved and probable reserves that are expected to be recovered but that cannot yet be classified as reserves, or the P50 on the cumulative distribution of results from probabilistic estimates.