MARATHON OIL CORP
Form 10-K
February 22, 2013

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, 2012
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 þ No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ
Indicate by check mark whether the registrant is a large accelerated filer, accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No þ

The aggregate market value of Common Stock held by non-affiliates as of June 29, 2012: $17,991 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 707,709,281 shares of Marathon Oil Corporation Common Stock outstanding as of January 31, 2013.

Documents Incorporated By Reference:

Portions of the registrant's proxy statement relating to its 2013 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

MARATHON OIL CORPORATION

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

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Definitions

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

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

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

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

bbl – One stock tank barrel, which is 42 United States gallons liquid volume.

bbld – Barrels per day.

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

bcf – Billion cubic feet.

boe – Barrels of oil equivalent.

boed – Barrels of oil equivalent per day.

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

btu – British thermal unit, an energy equivalence measure.

DD&A – Depreciation, depletion and amortization.

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

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

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

Drilling Moratorium – As a result of an explosion and significant spill from a deepwater rig in the Gulf of Mexico, the United States Department of the Interior issued a drilling moratorium on May 30, 2010 to suspend the drilling of deepwater wells, and prohibit drilling any new deepwater wells. The moratorium was lifted on October 12, 2010.

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, an liquefied natural gas production company located in E.G. in which we own a 60 percent equity interest.

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

EPA – Environmental Protection Agency.

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

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

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

FASB – Financial Accounting Standards Board.

FPSO – Floating production, storage and offloading vessel.

IFRS – International Financial Reporting Standards.

IG – Our Integrated Gas segment which 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.
Liquid hydrocarbon – Collectively, crude oil, condensate and natural gas liquids.
LNG – Liquefied natural gas.
LPG – Liquefied petroleum gas.
Marathon – The consolidated company prior to the June 30, 2011 spin-off of the downstream business.
Marathon Oil – The company as it exists following the June 30, 2011 spin-off of the downstream business.
Marathon Petroleum Corporation ("MPC") – The separate independent company which now owns and operates the downstream business.
mbbl – Thousand barrels.
mbbld – Thousand barrels per day.
mboe – Thousand barrels of oil equivalent.
mboed – Thousand barrels oil equivalent per day.
mcf – Thousand cubic feet.
mmbbl – Million barrels.
mmboe – Million barrels of oil equivalent.
mmbtu – Million British thermal units.
mmcfd – Million cubic feet per day.
mmt – Million metric tonnes.
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.
OECD – Organization for Economic Cooperation and Development.
Oklahoma Resource Basins – Areas in Oklahoma including the Anadarko Woodford shale, the Mississippi Sooner lime, the Granite wash, the Tonkawa, the Cleveland, and the Marmaton plays.
OPEC – Organization of Petroleum Exporting Countries.
OSM – Our Oil Sands Mining segment which mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.
Productive well – A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.
Proved reserves – Proved oil, natural gas and synthetic crude oil reserves are those quantities of oil, natural gas and synthetic crude oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible.
Proved developed reserves – Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.
Proved undeveloped reserves – Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
PSC – Production sharing contract.
Quest CCS – Quest Carbon Capture and Storage project at the AOSP in Alberta, Canada.
Reserve replacement ratio – A ratio which measures the amount of proved reserves added to our reserve base during the year relative to the amount of oil and gas produced.

Royalty interest – An interest in an oil or natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.
SAGE – United Kingdom Scottish Area Gas Evacuation system composed of a pipeline and processing terminal.
SAR or SARs – Stock appreciation right or stock appreciation rights.
SEC – United States Securities and Exchange Commission.
Seismic – An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures and 4-D factors in changes that occurred over time).
Total depth ("TD") – The bottom of a drilled hole, where drilling is stopped, logs are run and casing is cemented.
Total proved reserves – The summation of proved developed reserves and proved undeveloped reserves.
U.K. – United Kingdom.
Undeveloped acreage – Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
U.S. – United States of America.
U.S. GAAP – Accounting principles generally accepted in the U.S.
WCS – Western Canadian Select, an oil index benchmark price.
Working interest ("WI") – The interest in a mineral property which gives the owner that share of production from the property. A working interest owner bears that share of the costs of exploration, development and production in return for a share of production. Working interests are typically burdened by overriding royalty interest or other interests.
WTI – West Texas Intermediate crude oil, an oil index benchmark price.

Disclosures Regarding Forward-Looking Statements

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

Forward-looking statements in this Annual Report on Form 10-K may include, but are not limited to: levels of revenues, income from operations, net income or earnings per share; levels of capital, exploration, environmental or maintenance expenditures; the success or timing of completion of ongoing or anticipated capital, exploration or maintenance projects; volumes of production or sales of liquid hydrocarbons, natural gas, and synthetic crude oil; levels of worldwide prices of liquid hydrocarbons and natural gas; levels of liquid hydrocarbon, natural gas and synthetic crude oil reserves; the acquisition or divestiture of assets; the effect of restructuring or reorganization of business components; the potential effect of judicial proceedings on our business and financial condition; levels of common share repurchases; the impact of government legislation and budgetary and tax measures; and the anticipated effects of actions of third parties such as competitors, or federal, foreign, state or local governments and regulatory authorities.

PART I

Item 1. Business

General

Marathon Oil Corporation was incorporated in 2001 and is an international energy company engaged in exploration and production, oil sands mining and integrated gas with operations in the U.S., Angola, Canada, E.G., Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq, Libya, Norway, Poland and the U.K. We are based in Houston, Texas with our corporate headquarters at 5555 San Felipe Street, Houston, Texas 77056-2723 and a telephone number of (713) 629-6600.

On June 30, 2011, the spin-off of Marathon's downstream business was completed, creating two independent energy companies: Marathon Oil and MPC. Marathon stockholders at the close of business on the record date of June 27, 2011 received one share of MPC common stock for every two shares of Marathon common stock held. A private letter ruling received in June 2011 from the IRS affirmed the tax-free nature of the spin-off. Activities related to the downstream business have been treated as discontinued operations in 2011 and 2010, with additional information in Item 8. Financial Statements and Supplementary Data - Note 3 to the consolidated financial statements.

Strategy and Results Summary

Assets within our three segments are at various stages in their lifecycle: base, growth or exploration. We have a stable group of base assets, which include our OSM and IG segments and E&P assets in E.G., Libya, Norway, the U.K. and certain U.S. operations. These assets generate much of the cash that will be available for investment in our growth assets and exploration projects. Growth assets are where we expect to make significant investment in order to realize oil and gas production and reserve increases. We are focused on U.S. liquid hydrocarbon growth by developing unconventional liquids-rich plays, including the Eagle Ford and Bakken shales, and the Oklahoma Resource Basins. In addition to the U.S. shale plays, growth assets include deepwater discoveries and developments offshore Angola, our Canadian in-situ assets, certain Gulf of Mexico blocks and the Kurdistan Region of Iraq. We also invest in exploration prospects that have significant value potential. Our areas of exploration are E.G., Ethiopia, Gabon, the Gulf of Mexico, Kenya, the Kurdistan Region of Iraq, Libya, Norway and Poland. We continually evaluate ways to optimize our portfolio through acquisitions and divestitures, with a previously stated goal of divesting between $1.5 billion and $3.0 billion of non-core assets over the period of 2011 through 2013. For the two-year period ended December 31, 2012, we entered into agreements for approximately $1.3 billion in divestitures, of which $785 million were completed. The remaining $545 million in asset sales were completed by February 22, 2013.

We ended 2012 with proved reserves of 2 bboe, a 12 percent increase over 2011. Average sales volumes were 282 mbbld of liquid hydrocarbon, 902 mmcfd of natural gas and 47 mbbld of synthetic crude oil, with 62 percent of our liquid hydrocarbon sales volumes from international operations, for which average realizations have exceeded WTI crude prices. During 2012, we invested in the development of assets totaling $5.4 billion in capital, investment and exploration spending and made acquisitions of approximately $1 billion. We expect continued spending, primarily funded with cash flow from operations or portfolio optimization, in exploration and development activities in order to realize continued reserve and sales growth. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-Outlook, for discussion of our $5.2 billion capital, investment and exploration budget for 2013.

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

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The map below illustrates the locations of our worldwide operations.

Segment and Geographic Information

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

Exploration and Production Segment

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

We are engaged in oil and gas exploration, development and/or production activities in the U.S., Angola, Canada, Ethiopia, E.G., Gabon, Kenya, the Kurdistan Region of Iraq, Libya, Norway, Poland, and the U.K.

Liquids-Rich Shale Plays

Eagle Ford - As of December 31, 2012 we have 230,000 net acres in the core of the Eagle Ford shale, with an additional 100,000 non-core acres. In the fourth quarter of 2011, we made our most significant investment in the Eagle Ford shale play of south Texas when we closed several acquisitions for a total cash consideration of $4.5 billion. Throughout 2012, we rationalized our position with several acquisitions totaling $1 billion and select divestitures of acreage located outside the core of the Eagle Ford shale. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for additional information about these acquisitions.

As of December 31, 2012, we had 379 gross (262 net) producing wells in the Eagle Ford shale. We realized significant efficiencies in drilling during 2012, reducing the average drilling time per well to 23 days, reaching TD on 248 gross (178 net)operated wells and brought 215 gross (154 net) operated wells to sales. Approximately one-third of our 2013 capital budget is dedicated to the Eagle Ford shale. Our plans include drilling and completing 275 - 320 gross (215 - 250 net) operated wells in 2013. We have undertaken a number of pilot tests across the acreage to assist in identifying appropriate spacing, landing zones and completion techniques for the Eagle Ford. Results from vertical landing zone pilots and completions pilots are ongoing and incorporated into operations continuously. Initial analysis of spacing pilot results are expected by the end of 2013 and may result in improvements to our overall development plans for the field.

Eagle Ford average net sales for 2012 were 34 mboed, composed of 23 mbbld of crude oil, 5 mbbld of NGLs and 37 mmcfd of natural gas. Our 2012 exit rate of production was over 65 mboed, which is fourfold increase over December 2011. We are able to transport approximately 60 percent of our Eagle Ford production by pipeline and additional contract negotiations and facility designs are underway.

We continue to build infrastructure to support our liquid hydrocarbon and natural gas production growth across the operating area. Approximately 370 miles of gathering lines were installed in 2012, and 12 new central gathering and treating facilities were commissioned, with 7 additional facilities in various stages of planning or construction. We also own and operate the Sugarloaf gathering system, a 42-mile natural gas pipeline through the heart of our acreage in Karnes, Atascosa, and Bee Counties of south Texas.

Bakken – We hold approximately 410,000 net acres in the Bakken shale oil play in North Dakota and eastern Montana. Throughout 2012, we continued selective acreage acquisitions and leasing, further expanding a new prospect area. We moved from 20-stage to 30-stage hydraulic fracturing in 2011 to increase both production rates and estimated ultimate recovery from our Bakken shale wells. We also continued to alter completion techniques seeking continuous improvement in well performance. We reached TD on 88 gross (76 net) operated wells and brought to sales 98 gross (84 net) operated wells in 2012. Our Bakken shale program includes plans to drill 190 - 220 gross (65 - 70 net) wells in 2013, of which 60 - 70 net wells will be operated by us.

Our net sales from the Bakken shale averaged 29 mboed, composed of 27 mbbld of crude oil, 1 mbbld NGLs and 8 mmcfd natural gas in 2012, a 70 percent increase on a barrel of oil equivalent basis over 2011. Our production exit rate for 2012 was approximately 35 mboed. We sell our Bakken production into various markets via truck, railcar and other marketing options. We have, and continue to secure, long-term agreements to transport portions of our current and forecasted liquid hydrocarbon production to market via third-party gathering systems.

Oklahoma Resource Basins – In the Anadarko Woodford shale play in Oklahoma, we hold 163,000 net acres of which approximately 100,000 net acres are held by production. In 2012, we executed an operated drilling program focused on the liquids-rich areas of the play, reached TD on 25 gross (20 net) operated wells and brought to sales 29 gross (25 net) operated wells. In 2013, we plan to drill 42 - 50 gross (15 - 19 net) wells, of which 12 - 14 net wells will be operated. The Anadarko Woodford shale averaged net sales of 8 mboed, composed of 1 mbbld of crude oil, 2 mbbld of NGLs and 29 mmcfd of natural gas, during 2012, a more than threefold increase over 2011 on a barrel of oil equivalent basis. Our 2012 exit rate of production was 10 mboed.

Other areas of potential growth exist in Oklahoma and we are currently evaluating opportunities on legacy assets where the acreage is held by production. Future activity in the Oklahoma Resource Basins will be dependent upon the recovery of natural gas and natural gas liquids prices. See below for additional discussion of our conventional, primarily natural gas, production operations in Oklahoma.

United States

Alaska – In April 2012, we entered into an agreement to sell all of our assets in Alaska in a transaction valued at $375 million before closing adjustments. Those assets include operated and non-operated interests in 10 natural gas fields in the Cook Inlet and adjacent Kenai Peninsula of Alaska and majority ownership in four operated natural gas pipelines totaling 140 miles. The transaction closed in January 2013 for proceeds of $195 million subject to a six-month escrow of $50 million for various indemnities. Net sales from Alaska averaged 92 mmcfd in 2012.

Colorado – We hold leases with natural gas production in the Piceance Basin of Colorado, located in the Greater Grand Valley field complex and 154,000 net acres in the liquids-rich Niobrara shale located in the DJ Basin of northern Colorado, southeastern Wyoming and Nebraska. We drilled 17 gross (12 net) operated wells in the DJ Basin during

2012. Net sales from these two areas averaged 3 mboed in 2012. We have no plans for operated drilling in Colorado in 2013.

Oklahoma – We have long-established operated and non-operated conventional production in several Oklahoma fields from which 2012 sales averaged 2 mbbld of liquid hydrocarbons and 51 mmcfd of natural gas. In 2012, we participated in 11 gross (1 net), non-operated wells in the state. We also drilled 1 operated well. Plans for 2013 include drilling 11 gross (2 net) wells, targeting liquids.

Texas/North Louisiana/New Mexico – In east Texas and north Louisiana, we hold 184,000 net acres. Approximately 20,000 of the acres are in the Haynesville and Bossier natural gas shale plays. Most of the acreage in these shale plays is held by production. We participated in 5 gross (1 net) non-operated wells in the area during 2012. Conventional production was primarily from the Mimms Creek, Pearwood and Oletha fields in 2012, with net sales averaging 6 mboed.

We also participate in several non-operated Permian Basin fields in west Texas and New Mexico. Net sales from this area averaged 7 mboed in 2012. We plan continued carbon dioxide flood programs in the Seminole and Vacuum fields during 2013.

Wyoming – We have ongoing enhanced oil recovery waterflood projects at the mature Bighorn Basin and Wind River Basin fields and initiated an additional enhanced oil recovery project at our 100 percent owned and operated Pitchfork field in 2012. We have conventional natural gas operations in the Greater Green River Basin and unconventional coal bed natural gas operations in the Powder River Basin. In 2012, we drilled 2 gross (2 net) operated development wells in Wyoming, which included 1 wellbore re-entry. We plan to drill 1 gross (1 net) operated well in 2013.

Our Wyoming net sales averaged 17 mbbld of liquid hydrocarbons and 68 mmcfd of natural gas during 2012. 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.

Over the next two years, we plan to plug and abandon over 600 wells in the Powder River Basin as we wind down those operations due to poor economics. See Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements for impairments of our Powder River Basin asset taken in recent years due to declining natural gas prices and reduced development plans.

Gulf of Mexico – Production

On December 31, 2012, we held material interests in 7 producing fields, 4 of which are company-operated. Average net sales for 2012 from the Gulf of Mexico were 22 mbbld of liquid hydrocarbons and 19 mmcfd of natural gas.

We operate and have a 65 percent working interest in the Ewing Bank Block 873 platform which is located 130 miles south of New Orleans, Louisiana. The platform 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. In 2012, seismic data that was acquired in 2011 on Blocks 873 and 917 was processed in order to refine existing opportunities and to identify others for a development drilling campaign that is planned to start in 2015.

We own a 50 percent working interest in the non-operated Petronius field on Viosca Knoll Blocks 786 and 830 located 130 miles southeast of New Orleans, which includes 14 producing wells. The Petronius platform is capable of providing processing and transportation services to nearby third-party fields. During 2012, we acquired 4-D seismic data in order to identify potential future drilling opportunities.

We hold a 30 percent working interest in the non-operated Neptune field located on Atwater Valley Block 575, 120 miles off the coast of Louisiana. The development includes seven subsea wells tied back to a stand-alone platform. A well that had been producing from a deeper horizon was recompleted to the main producing zone in 2012.

The Droshky and Ozona developments off the coast of Louisiana are both expected to reach abandonment pressures in the first half of 2013. We have a 100 percent operated working interest in the Droshky development located on Green Canyon Block 244 and a 68 percent operated working interest in Ozona which is located on Garden Banks Block 515.

In February 2013, we sold our 34 percent non-operated interest in the Neptune gas plant that is located onshore Louisiana. The transaction value, before closing adjustments, was $170 million.

Gulf of Mexico – Exploration

We have a portfolio of over 18 prospects with multiple drilling opportunities in the Gulf of Mexico. As we evaluate these opportunities for drilling, we plan to seek partners to reduce our exploration risk on individual projects.

A successful deepwater oil discovery well was drilled on the Gunflint prospect, located on Mississippi Canyon Block 948, in 2008. We own a 15 percent non-operated working interest in this prospect. One appraisal well was drilled in 2012 confirming expected reservoir properties and establishing the commercial viability of the field. An additional appraisal well began drilling in February 2013. Development planning is ongoing.

In the first quarter of 2009, we participated in a deepwater oil discovery on the Shenandoah prospect located on Walker Ridge Block 52. We own a 10 percent interest in this non-operated prospect. The first appraisal well began drilling in June 2012, has reached TD and is currently being evaluated.

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In the third quarter of 2012, we resumed drilling an exploratory well on the Innsbruck prospect located on Mississippi Canyon Block 993 which had been temporarily suspended under the federal government's Drilling Moratorium. Upon reaching TD in November 2012, the well was determined to be dry. The well costs and related unproved property costs were charged to exploration expense in 2012. We have a 45 percent operated working interest in Innsbruck.

We hold a 30 percent non-operated working interest in Green Canyon Blocks 403 and 404 in the Kilchurn prospect. The operator commenced drilling in the Kilchurn prospect in December 2011. In the second quarter of 2012, the well was determined to be dry. The well costs and related unproved property costs were charged to exploration expense in 2012.

In October 2011, we received approval of an exploration plan from the BOEMRE for the Key Largo prospect located on Walker Ridge Block 578. We have a 60 percent working interest and are the operator of this prospect. Drilling is expected in 2014.

We currently hold a 100 percent operated working interest in the Madagascar prospect located on DeSoto Canyon Block 757. Our exploration plan was approved by the BOEMRE in 2012. We expect to drill the first exploration well on the prospect in 2013 at a lower working interest.

Africa

Equatorial Guinea - We own a 63 percent operated working interest under a PSC in the Alba field which is offshore E.G. During 2012, E.G. net liquid hydrocarbon sales averaged 36 mbbld, and net natural gas sales averaged 428 mmcfd. Operational availability for 2012 averaged 95 percent.

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 expected in late 2013 or early 2014.

We have an 80 percent operated working interest in exploratory Block A-12 offshore Bioko Island, located immediately west of our operated Alba Field.

We also own a 52 percent interest in Alba Plant LLC, an equity method investee that operates an onshore LPG processing plant located on Bioko Island. Alba field natural gas is processed by the LPG plant. Under a long-term contract at a fixed price per btu, the LPG plant extracts secondary condensate and LPG from the natural gas stream and uses some of the dry natural gas in its operations. During 2012, the gross quantity of natural gas supplied to the LPG production facility was 863 mmcfd, and 7 mbbld of secondary condensate and 20 mbbld of LPG were produced by Alba Plant LLC. Our share of the income ultimately generated by the subsequent export of secondary condensate and LPG produced by Alba Plant LLC is reflected in our E&P segment.

As part of our IG segment, we own 45 percent of AMPCO and 60 percent of EGHoldings, both of which are accounted for as equity method investments. AMPCO operates a methanol plant and EGHoldings operates an LNG production facility, both located on Bioko Island. Dry natural gas from the Alba field, which remains after the condensate and LPG are removed by Alba Plant LLC, is supplied to both of these facilities under long-term contracts at fixed prices. Because of the location of and limited local demand for natural gas in E.G., we consider the prices under the contracts with Alba Plant LLC, AMPCO and EGHoldings to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances. Our share of the income ultimately generated by the subsequent export of methanol produced by AMPCO and LNG produced by EGHoldings is reflected in our IG segment as discussed below. During 2012, the gross quantities of dry natural gas supplied to the methanol plant to the LNG production facility were 119 mmcfd and 639 mmcfd. Any remaining dry gas is returned offshore and reinjected into the Alba field for later production.

Libya - We hold a 16 percent working interest in the Waha concessions, which encompass almost 13 million acres located in the Sirte Basin of eastern Libya. During the first quarter of 2011, all production operations in Libya were suspended due to civil unrest. In the fourth quarter of 2011, limited production resumed from the Waha concessions, but we made no deliveries of hydrocarbons. Sales resumed in the first quarter of 2012 and averaged 45 mboed in 2012.

Angola – Offshore Angola, we hold 10 percent working interests in Blocks 31 and 32, both of which are non-operated. The discoveries on Blocks 31 and 32 represent several potential development hubs. In 2008, we received approval to proceed with the first deepwater development project, called the PSVM development, which includes the Plutao, Saturno, Venus and Marte discoveries and one successful appraisal well in the northeastern portion of Block 31. The

PSVM development utilizes a FPSO with a total of 48 production and injection wells. Development drilling began in 2010 and first production was in the fourth quarter of 2012, with first sales in February 2013. Our plans include continued development drilling with tie-in to the FPSO in order to reach a production plateau of 14 net mboed in the first half of 2014 which is expected to last through 2017.

Front-end engineering and design for the Kaombo development, located in the southeastern portion of Block 32, is underway. The development is expected to consist of two-105 mbbld FPSO. Project sanction is expected mid-2013 so that production from the Kaombo development is possible in 2016. We continue to assess other discoveries on Blocks 31 and 32 for development potential.

Gabon - We hold a 21 percent non-operated working interest in the Diaba License G4-223 and its related permit offshore Gabon, which covers 2.2 million gross (467,500 net) acres. The start of exploration drilling is expected in the first quarter of 2013.

Kenya - We hold a 50 percent non-operated working interest in Block 9 and a 15 percent non-operated working interest in Block 12A which are located in northwest Kenya, covering 12.3 million gross (4.4 million net) acres. Seismic has been acquired on Block 9 and seismic acquisition on Block 12A is underway. The first exploratory well is expected to begin drilling on Block 9 in the second quarter of 2013. We have the right to assume the role of operator on Block 9 if a commercial discovery is made.

Ethiopia - In January 2013, government approval was received for our acquisition of a 20 percent non-operated interest in the onshore South Omo concession in Ethiopia. The concession has an area of approximately 7.3 million gross (1.5 million net) acres. The Sabisa 1 exploration well began drilling in January 2013 and is expected to take approximately 60 days to reach the planned TD of 8,500 ft.

Europe

Norway – At the end of 2012, we operated 10 licenses and held interests in six non-operated licenses, which encompass approximately 240,000 net acres on the offshore Norwegian continental shelf. In 2012, net sales from Norway averaged 81 mbbld of liquid hydrocarbons and 53 mmcfd of natural gas.

The Alvheim development is comprised of the Kameleon, East Kameleon and Kneler fields (PL 036C, PL 088BS and PL 203), in each of which we have a 65 percent working interest, and the Boa field, in which we have a 58 percent working interest. It is produced to the Alvheim complex which consists of a FPSO with subsea infrastructure. In 2011 and 2012, due to debottlenecking efforts, capacity of the FPSO increased by 15 mbbld gross. Peak oil production of 157 mbbld gross (94 mbbld net) was reached in the first quarter of 2012. During 2012 operational availability of the Alvheim development was 96 percent including planned maintenance activities, while unplanned downtime was minimal at 3 percent. Produced oil is transported by shuttle tanker and produced natural gas is transported to the SAGE system by pipeline. At the end of 2012, the Alvheim development included 14 producing wells and 2 water disposal wells.

In October 2012, we took over operatorship of the nearby Vilje field (PL 036D), in which we own a 47 percent working interest, which began producing through the Alvheim complex in August 2008. At the end of 2012, 2 wells were producing and an additional development, Vilje Sor, had been approved. Production from Vilje Sor is estimated to begin near the end of 2013.

The Volund field (PL 150 and PL 150BS) is tied back to the Alvheim complex, which is five miles to the north. The Volund development, in which we own a 65 percent operated working interest, consists of three production wells and one water injection well at December 31, 2012. The drilling of an additional development well at Volund was completed in the fourth quarter 2012 and first production commenced in January 2013.

The Viper/Kobra (PL 203) oil discovery, in the immediate vicinity of the Volund Field, was announced in November 2009. We hold a 65 percent operated working interest in Viper/Kobra. Along with our partners, we are evaluating a possible tie-back to the Alvheim complex.

The Boyla field, formerly the Marihone discovery, (PL 340) is located approximately 17 miles south of Alvheim. In October 2012, the Norwegian Ministry of Petroleum and Energy approved the plan for the development and operation of the Boyla field in which we hold a 65 percent operated working interest. First production from Boyla is expected in the fourth quarter of 2014. Near Boyla is the Caterpillar discovery (PL340BS), which was made in 2011. It is being evaluated as a tie-back to the Alvheim complex through Boyla.

Also offshore Norway, the Darwin (formerly Velsemoy) well is expected to begin drilling late in the first quarter of 2013 on PL 531 in which we hold a 10 percent non-operated working interest. Drilling is also expected to commence in the third quarter of 2013 on the Sverdrup well on PL 330 where we hold a 30 percent non-operated working interest.

In January 2013, we were awarded a 20 percent non-operated working interest in PL 694, which consists of three blocks, south of the Sverdrup prospect area, in the Norwegian Sea. We were also awarded additional acreage in the North Sea, north of the Alvheim area in PL 203B. Our 65 percent working interest and role as operator are the same as PL 203. In addition, effective January 2013, we withdrew from two licenses (PL505 and PL505B). In 2013, we will operate 9 licenses and have an interest in approximately 225,000 net acres.

United Kingdom – Net sales from the U.K. averaged 16 mbbld of liquid hydrocarbons and 48 mmcfd of natural gas in 2012. 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 platform, respectively. The East Brae platform also hosts the nearby Braemar field in which we have a 28 percent working interest. Two development wells were completed at West Brae in early 2011 and we continue to pursue Brae complex projects designed to maximize natural gas recovery and maintain deliverability rates to the U.K. market.

The strategic location of the Brae platforms, along with pipeline and onshore infrastructure, has generated third-party processing and transportation business since 1986. Currently, the operators of twenty-five third-party fields are contracted to use the Brae system and 67 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 Brae group owns a 50 percent interest in the non-operated SAGE system. The SAGE pipeline transports natural gas from the Brae area, and the third-party Beryl area, and has a total wet natural gas capacity of 1.1 bcf per day. The SAGE terminal at St. Fergus in northeast Scotland processes natural gas from the SAGE pipeline as well as approximately 1 bcf per day of third-party natural gas.

In the U.K. Atlantic Margin west of the Shetland Islands, we own an average 30 percent working interest in the non-operated Foinaven area complex, consisting of a 28 percent working interest in the main Foinaven field, a 47 percent working interest in East Foinaven and a 20 percent working interest in the T35 and T25 fields. The export of Foinaven liquid hydrocarbons is via shuttle tanker from the FPSO to market. All natural gas sales are to the non-operated Magnus platform for use as injection gas. An ongoing upgrade of equipment on the FPSO is expected to extend the life of the fields from 2017 to 2021. Additionally, the planned installation of replacement flowlines should secure the long-term integrity of the subsea infrastructure.

Poland – As of December 31, 2012, we hold a 51 percent working interest in 9 concessions, an 85 percent working interest in one concession and a 100 percent interest in one concession for a total of approximately 1.2 million net acres. We are operator under all licenses. In 2012, we reached TD on 5 gross (3 net) operated wells and in 2013 have reached TD on one more gross (0.85 net) well. Since late 2011, we have conducted a continuous drill, core and diagnostic fluid injection test program ("DFIT"). Following these DFIT evaluations, we plan to hydraulically fracture select wells. We are evaluating all data collected through drilling in addition to proprietary 2-D seismic acquired in 2011, 2012, and 2013.

Canada

We hold interests in both operated and non-operated exploration stage oil sand leases in Alberta, Canada, which would be developed using in-situ methods of extraction. These leases cover approximately 143,000 gross acres (52,000 net) in four project areas: Namur, in which we hold a 60 percent operated interest; Birchwood, in which we hold a 100 percent operated interest; Ells River, in which we hold a 20 percent non-operated interest and Saleski in which we hold a 33 percent non-operated interest.

During the first quarter of 2012, we submitted a regulatory application for a proposed 12 mbbld steam assisted gravity drainage ("SAGD") project at Birchwood. Pending regulatory approval, project sanction is expected in 2014, with first oil projected in 2017. Exploration activities leading up to this application included drilling approximately 100 stratigraphic test wells in the winter of 2010 to 2011 and a 3-D seismic survey in 2012.

Other International

Kurdistan Region of Iraq - In aggregate, we have access to approximately 215,000 net acres in the Kurdistan Region of Iraq. We have interests in two non-operated blocks located north-northwest of Erbil: Atrush, in which our working interest is 20 percent, and Sarsang, in which our working interest is 25 percent. Through December 31, 2012, discoveries have been made in each block and successful appraisal wells were drilled and tested on both blocks during 2012, including the discovery of additional hydrocarbon-bearing zones. Further appraisal and development drilling is planned for 2013. Additional exploration drilling is proceeding on the Sarsang block. Two exploration wells commenced in late 2012 with results expected in the first quarter of 2013. A further exploration well will be drilled during 2013.

The exploration and appraisal work on the Atrush block resulted in a declaration of commerciality being submitted by the operator in November 2012. A field development plan will be submitted for government approval in May 2013. This plan will outline the forward commitments required to develop the field in the most economic way. The multiple prospects on the Sarsang block require additional exploration and appraisal work through 2013.

We also have PSCs for operatorship of the Harir and Safen blocks located northeast of Erbil. After selling down a portion of our interest in the third quarter of 2012 to balance our portfolio, our working interest is 45 percent in each block. We have completed an extensive 2-D seismic program on both blocks. The first exploration well on the Harir block commenced drilling in July 2012, reached TD in December 2012, was tested and deemed to be dry. We plan to start an exploration well on the Safen block and a second exploration well on the Harir block in the first half of 2013.

Acquisitions and Dispositions

We continually evaluate ways to optimize our portfolio through acquisitions and dispositions, with a previously stated goal of divesting between $1.5 billion and $3 billion of non-core assets over the period of 2011 through 2013. For the two-year period ended December 31, 2012, we entered into agreements for approximately $1.3 billion in divestitures, of which $785 million were completed. The remaining $545 million in asset sales were completed by February 22, 2013. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements for additional information about the acquisitions and Note 6 for additional information about the dispositions.

Acquisitions

In the second half of 2012, we closed acquisitions of approximately 25,000 net acres in the core of the Eagle Ford shale at transaction values totaling approximately $1 billion before closing adjustments. The acquisitions included wells producing 12 net mboed at closing.

In October 2012, we entered into an agreement to acquire a 20 percent non-operated working interest in the South Omo concession onshore Ethiopia with an effective date of August 17, 2012. Ethiopian government approval was received and this transaction closed in January 2013 for cash consideration of $40 million, before closing adjustments, plus an additional payment of $10 million due upon declaration of a commercial discovery.

In July 2012, we entered into an agreement to acquire non-operated positions in two onshore exploration blocks in northwest Kenya. Upon closing the $32 million transaction in October 2012, we now hold a 50 percent working interest in Block 9 and a 15 percent working interest in Block 12A.

In June 2012, we entered an agreement to acquire a 21 percent non-operated working interest in the Diaba License G4-223 and its related permit onshore Gabon. The transaction closed in October 2012.

During June 2012, we signed a new production sharing contract with the government of E.G. for the exploration of Block A-12 offshore Bioko Island, located immediately west of our operated Alba Field. We have an 80 percent operated working interest in this block. The contract was ratified by the government in the third quarter of 2012. We also acquired an additional interest in Block D, bringing our working interest to 80 percent.

Dispositions

In February 2013, we entered an agreement to convey our interests in the Marcellus natural gas shale play to the operator.

In December 2012, we entered into an agreement to sell our E&P segment's interest in the Neptune gas plant, located onshore Louisiana. The transaction, with a value of $170 million before closing adjustments, closed in February 2013.

In the third quarter of 2012, we sold approximately 5,800 net undeveloped acres located outside the core of the Eagle Ford shale for proceeds of $9 million, recording a loss of $18 million.

In June 2012, we agreed to sell-down our interests in the Harir and Safen blocks in the Kurdistan Region of Iraq. The transaction subsequently closed and we received cash proceeds of $140 million before closing adjustments, so that we now have a 45 percent working interest in each of the two blocks.

In May 2012, we executed agreements to relinquish our operatorships of, and participating interests in, the Bone Bay and Kumawa exploration licenses in Indonesia. Government ratification of the agreements was received during the third quarter of 2012, which released us from our obligations and further commitments related to these licenses.

In April 2012, we entered into an agreement to sell all of our assets in Alaska in a transaction valued at $375 million before closing adjustments. The transaction closed in January 2013 for proceeds of $195 million subject to a six-month escrow of $50 million for various indemnities.

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 includes our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline L.L.C., as well as certain other oil pipeline interests, including the Eugene Island pipeline system. A pretax gain of $166 million was recorded in the first quarter of 2012.

The above discussions include forward-looking statements with respect to the timing and levels of future liquid hydrocarbon and natural gas production, anticipated future exploratory and development drilling activity, expectations for improvements to development plans from the optimization of well spacing in the Eagle Ford shale play, planned use of carbon dioxide flood programs, the timing of reaching abandonment pressures for the Droshky and Ozona developments, the expected life extension of the Foinaven fields, the timing of project sanction and first oil from the SAGD project, and the goal of divesting between $1.5 and $3.0 billion of non-core assets over the period of 2011 through 2013. The projected asset dispositions through 2013 are based on current expectations, estimates, and projections and are not guarantees of future performance. Some factors which could possibly affect

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these forward-looking statements include pricing, supply and demand for petroleum products, the amount of capital available for exploration and development, regulatory constraints, drilling rig availability, the inability to obtain or delay in obtaining necessary government and third-party approvals and permits, unforeseen hazards such as weather conditions, natural disasters, acts of war or terrorist acts and the governmental or military response, and other geological, operating and economic considerations. The SAGD project may further be affected by board approval, transportation logistics, availability of materials and labor, and other risks associated with construction projects. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Productive and Drilling Wells

For our E&P segment, the following tables set forth gross and net productive wells and service wells as of December 31, 2012, 2011 and 2010 and drilling wells as of December 31, 2012.

	Productive Wells[a]							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2012								
U.S.	6,191	2,315	3,208	1,906	2,328	736	66	30
E.G.	—	—	14	9	4	3	—	—
Other Africa	1,050	171	6	1	101	16	5	1
Total Africa	1,050	171	20	10	105	19	5	1
Total Europe	77	34	40	16	28	11	1	1
Total Other International	—	—	—	—	—	—	4	1
Worldwide	7,318	2,520	3,268	1,932	2,461	766	76	33
2011								
U.S.	5,809	2,058	3,121	1,876	2,313	734		
E.G.	—	—	14	9	4	3		
Other Africa[b]	—	—	—	—	1	—		
Total Africa	—	—	14	9	5	3		
Total Europe	73	31	40	16	28	10		
Worldwide	5,882	2,089	3,175	1,901	2,346	747		
2010								
U.S.	4,818	1,860	3,145	1,905	2,466	746		
E.G.	—	—	13	9	5	3		
Other Africa	1,022	168	3	—	94	16		
Total Africa	1,022	168	16	9	99	19		
Total Europe	71	30	40	16	29	11		
Worldwide	5,911	2,058	3,201	1,930	2,594	776		

(a) Of the gross productive wells, wells with multiple completions operated by us totaled 188, 168 and 164 as of December 31, 2012, 2011 and 2010. Information on wells with multiple completions operated by others is unavailable to us.

(b) As operations were resuming in Libya at December 31, 2011, an accurate count of productive wells was not possible; therefore no Libyan wells are included in this number.

Drilling Activity

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

	Development				Exploratory				Total
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	
2012									
U.S.	172	21	2	195	117	13	9	139	334
Total Africa	4	—	—	4	1	—	—	1	5
Total Europe	3	—	—	3	—	—	—	—	3
Total Other International	—	—	—	—	—	—	—	—	—
Worldwide	179	21	2	202	118	13	9	140	342
2011									
U.S.	46	17	3	66	37	4	1	42	108
Total Africa[(a)]	2	—	—	2	—	—	—	—	2
Total Europe	2	—	—	2	—	—	—	—	2
Total Other International	—	—	—	—	—	—	1	1	1
Worldwide	50	17	3	70	37	4	2	43	113
2010									
U.S.	35	46	1	82	20	11	3	34	116
Total Africa	5	—	—	5	1	—	—	1	6
Total Europe	2	—	—	2	—	—	—	—	2
Total Other International	—	—	—	—	1	—	1	2	2
Worldwide	42	46	1	89	22	11	4	37	126

(a) Activity in Libya through February 2011.

Acreage

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

The following table sets forth, by geographic area, the gross and net developed and undeveloped E&P acreage held in our E&P segment as of December 31, 2012.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
U.S.	1,703	1,271	1,298	1,036	3,001	2,307
Canada	—	—	143	55	143	55
Total North America	1,703	1,271	1,441	1,091	3,144	2,362
E.G.	45	29	183	164	228	193
Other Africa	12,922	2,109	16,069	4,856	28,991	6,965
Total Africa	12,967	2,138	16,252	5,020	29,219	7,158
Total Europe	186	91	3,131	1,487	3,317	1,578
Other International	—	—	571	195	571	195

Worldwide	14,856	3,500	21,395	7,793	36,251	11,293

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

	Net Undeveloped Acres Expiring		
(In thousands)	2013	2014	2015
U.S.	436	189	130
Canada	—	—	—
Total North America	436	189	130
E.G.	—	36	—
Other Africa	858	—	189
Total Africa	858	36	189
Total Europe	—	216	1,155
Other International	—	—	49
Worldwide	1,294	441	1,523

Marketing and Midstream

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

As discussed previously, we currently own and operate gathering systems and other midstream assets in some of our production areas. We are continually evaluating value-added investments in midstream infrastructure or in capacity in third-party systems.

Delivery Commitments

We have committed to deliver quantities of crude oil and natural gas to customers under a variety of contracts. As of December 31, 2012, those contracts for fixed and determinable amounts relate primarily to Eagle Ford liquid hydrocarbon production. A minimum of 54 mbbld is to be delivered at variable pricing through mid-2017 under two contracts. Our current production rates and proved reserves related to the Eagle Ford shale are sufficient to meet these commitments, but the contracts also provide for a monetary shortfall penalty or delivery of third-party volumes.

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 base and expansion 1 Scotford upgrader is at Fort Saskatchewan, northeast of Edmonton, Alberta. As of December 31, 2012, we own or have rights to participate in developed and undeveloped leases totaling approximately 216,000 gross (43,000 net) acres. The underlying developed leases are held for the duration of the project, with royalties payable to the province of Alberta.

The five year AOSP Expansion 1 was completed in 2011. The Jackpine mine commenced production under a phased start-up in the third quarter of 2010 and began supplying oil sands ore to the base processing facility in the fourth quarter of 2010. The upgrader expansion was completed and commenced operations in the second quarter of 2011. Synthetic crude oil sales volumes for 2012 were 47 mbbld and net of royalty production was 41 mbbld. Phase one of debottlenecking opportunities was approved in 2011 and is expected to be completed in the second quarter of 2013. Future expansions and additional debottlenecking opportunities remain under review with no formal approvals expected until 2014.

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

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

In the fourth quarter of 2012, regulatory hearings were completed to consider the AOSP Jackpine mine expansion project. The regulatory application was submitted in 2007 and describes a potential oil sands mining development project of 100,000 gross bbld and includes additional mining areas, associated processing facilities utilities and infrastructure. A regulatory decision is expected to be published in the second quarter of 2013.

The governments of Alberta and Canada have agreed to partially fund Quest CCS for 865 million Canadian dollars. Financing has begun to be received over a period of 15 years, including development, construction and 10 years of operations. However, the funding is subject to conditions of achieving certain performance objectives. In the third quarter of 2012, the Energy and Resources Conservation Board ("ERCB"), Alberta's primary energy regulator, conditionally approved and the AOSP partners made a final investment decision on Quest CCS.

As announced in October 2012, we have engaged in discussions with respect to a potential sale of a portion of our 20 percent interest in the AOSP. Given the uncertainty of such a transaction, potential proceeds have not been included in our previously stated goal of divesting between $1.5 billion and $3 billion between 2011 and 2013.

The above discussion contains forward-looking statements with regard to discussions with respect to a potential sale of a portion of our 20 percent interest in the AOSP and the application for the Jackpine mine expansion. The potential sale of a portion of our interest in the AOSP is subject to successful negotiations and execution of definitive agreements. The Jackpine mine expansion could be affected by the inability to obtain or delay in obtaining necessary government and third-party approvals and permits. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and difficult to predict. The foregoing factors (among others) could cause actual results to differ materially from those set forth in the forward-looking statements.

Reserves

Estimated Reserve Quantities

The following table sets forth estimated quantities of our proved liquid hydrocarbon, natural gas and synthetic crude oil reserves based upon an unweighted average of closing prices for the first day of each month in the 12-month periods ended December 31, 2012, 2011 and 2010. Included in our liquid hydrocarbon reserves, are NGLs which represent approximately 6 percent of our total proved reserves on an oil equivalent basis. Approximately 70 percent of those NGLs reserves are associated with our U.S. unconventional liquids-rich plays.

Reserves are disclosed by continent, by country, if the proved reserves related to any geographic area, on an oil-equivalent barrel basis represent 15 percent or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent, or a continent. Approximately 70 percent of our proved reserves are located in OECD countries.

December 31, 2012	North America U.S.	Canada	Total	Africa E.G.	Other	Total	Europe Total	Grand Total
Proved Developed Reserves								
Liquid hydrocarbons (mmbbl)	198	—	198	68	168	236	84	518
Natural gas (bcf)	546	—	546	980	99	1,079	28	1,653
Synthetic crude oil (mmbbl)	—	653	653	—	—	—	—	653
Total proved developed reserves (mmboe)	289	653	942	231	185	416	88	1,446
Proved Undeveloped Reserves								
Liquid hydrocarbons (mmbbl)	277	—	277	42	59	101	5	383
Natural gas (bcf)	497	—	497	444	110	554	75	1,126
Total proved undeveloped reserves (mmboe)	360	—	360	116	77	193	18	571
Total Proved Reserves								
Liquid hydrocarbons (mmbbl)	475	—	475	110	227	337	89	901
Natural gas (bcf)	1,043	—	1,043	1,424	209	1,633	103	2,779
Synthetic crude oil (mmbbl)	—	653	653	—	—	—	—	653
Total proved reserves (mmboe)	649	653	1,302	347	262	609	106	2,017

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

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

The significant increase in proved reserves from 2011 to 2012 was primarily due to drilling programs within our shale plays and Eagle Ford acquisitions. Synthetic crude oil reserves also increased due to revised technical assessment and a change in royalty related to lower prices.

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

Preparation of Reserve Estimates

All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X. Liquid hydrocarbon, natural gas and synthetic crude oil reserve estimates are reviewed and approved by our Corporate Reserves Group, which includes our Director of Corporate Reserves and her staff of Reserve Coordinators. Liquid hydrocarbon and natural gas reserve estimates are developed or reviewed by Qualified Reserves Estimators ("QRE"). QRE are engineers or geoscientists with a minimum of a Bachelor of Science degree in the appropriate technical field, have a minimum of three years of industry experience with at least one year in reserve estimation and have completed Marathon Oil's Qualified Reserve Estimator training course. Reserve Coordinators screen all fields with proved reserves of 20 mmboe or greater every year to determine if a field review will be performed. Any change to proved reserve estimates in excess of 2.5 mmboe on a total field basis, within a single month, must be approved by Corporate Reserves Group management. All other proved reserve changes must be approved by a Reserve Coordinator.

Our Director of Corporate Reserves, who reports to our Chief Financial Officer, has a Bachelor of Science degree in petroleum engineering and a Master of Business Administration. Her 38 years of experience in the industry include 27 with Marathon Oil. She is active in industry and professional groups, having served on the Society of Petroleum Engineers ("SPE") Oil and Gas Reserves Committee ("OGRC"), chairing in 2008 and 2009. As a member of the OGRC, she participated in the development of the Petroleum Resource Management System. She chaired the development of the OGRC comments on the SEC's proposed modernization of oil and gas reporting and was a member of the American Petroleum Institute's Ad Hoc group that provided comments on the same topic.

Estimates of synthetic crude oil reserves are prepared by GLJ Petroleum Consultants of Calgary, Canada, third-party consultants. Their reports for all years are filed as exhibits to this Annual Report on Form 10-K. The team lead responsible for the estimates of our OSM reserves has 34 years of experience in petroleum engineering and has conducted surface mineable oil sands evaluations since 1986. He is a member of SPE, having served as regional director from 1998 through 2001. The second team member has 13 years of experience in petroleum engineering and has conducted surface mineable oil sands evaluations since 2009. Both are registered Practicing Professional Engineers in the Province of Alberta.

Audits of Estimates

Third-party consultants are engaged to provide independent estimates for fields that comprise 80 percent of our total proved reserves over a rolling four-year period for the purpose of auditing the in-house reserve estimates. We met this goal for the four-year period ended December 31, 2012. We established a tolerance level of 10 percent such that initial estimates by the third-party consultants are accepted if they are within 10 percent of our internal estimates. Should the third-party consultants' initial analysis fail to reach our tolerance level, both our team and the consultants re-examine the information provided, request additional data and refine their analysis if appropriate. This resolution process is continued until both estimates are within 10 percent. 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 our senior management is informed. This process did not result in significant changes to our reserve estimates in 2012 or 2011. There were no third-party audits performed in 2010.

During 2012, Netherland, Sewell & Associates, Inc. ("NSAI") prepared a Certification of December 31, 2011 reserves for the Alba field in E.G. The NSAI summary report is filed as an exhibit to this Annual Report on Form 10-K. Members of the NSAI team have many years of industry experience, having worked for large, international oil and gas companies before joining NSAI. The senior technical advisor has a Bachelor of Science degree in geophysics and over 15 years of experience in the estimation of and evaluation of reserves. The second member has a Bachelor of Science degree in chemical engineering and Master of Business Administration along with over 3 years of experience in estimation and evaluation of reserves. Both are licensed in the state of Texas.

Ryder Scott Company ("Ryder Scott") performed audits of several of our fields in 2012 and 2011. Their summary reports on audits performed in 2012 and 2011 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 has a Bachelor of Science degree in mechanical engineering, 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, 2012, 571 mmboe of proved undeveloped reserves were reported, an increase of 176 mmboe from December 31, 2011. The following table shows changes in total proved undeveloped reserves for 2012:

(mmboe)	
Beginning of year	395
Revisions of previous estimates	(13)
Improved recovery	2
Purchases of reserves in place	56
Extensions, discoveries, and other additions	201
Transfer to Proved Developed	(70)
End of year	571

Significant additions to proved undeveloped reserves during 2012 include 56 mmboe due to acquisitions in the Eagle Ford shale. Development drilling added 124 mmboe in the Eagle Ford, 35 mmboe in the Bakken and 15 mmboe in the Oklahoma Resource Basins shale play. A gas sharing agreement signed with the Libyan government in 2012 added 19 mmboe. Additionally, 30 mmboe were transferred from proved undeveloped to proved developed reserves in the Eagle Ford and 14 mmboe in the Bakken shale plays due to producing wells. Costs incurred in 2012, 2011 and 2010 relating to the development of proved undeveloped reserves, were $1,995 million $1,107 million and $1,463 million. A total of 27 mmboe was booked as a result of reliable technology. Technologies included statistical analysis of production performance, decline curve analysis, rate transient analysis, reservoir simulation and volumetric analysis.

The statistical nature of production performance coupled with highly certain reservoir continuity or quality within the reliable technology areas and sufficient proved undeveloped locations establish the reasonable certainty criteria required for booking reserves.

Projects can remain in proved undeveloped reserves for extended periods in certain situations such as behind-pipe zones where reserves will not be accessed until the primary producing zone depletes, large development projects which take more than five years to complete, and the timing of when additional gas compression is needed. Of the 571 mmboe of proved undeveloped reserves at December 31, 2012, 25 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 have increased by roughly 10 percent between 2004 and 2010. Production is now expected to experience a natural decline from facility-limited plateau production in 2014, or possibly 2015. During 2012, the project received the approval of the E.G. government, allowing design and planning work to progress towards implementation, with completion expected by mid-2016.

Proved undeveloped reserves for the North Gialo development, located in the Libyan Sahara desert, were booked for the first time as proved undeveloped reserves in 2010. This development, which is anticipated to take more than five years to be developed, is being executed by the operator and encompasses a continuous drilling program including the design, fabrication and installation of extensive liquid handling and gas recycling facilities. Anecdotal evidence from similar development projects in the region led to an expected project execution of more than five years from the time the reserves were initially booked. Interruptions associated with the civil unrest in 2011 have extended the project duration. There are no other significant undeveloped reserves expected to be developed more than five years after their original booking.

As of December 31, 2012, future development costs estimated to be required for the development of proved undeveloped liquid hydrocarbon, natural gas and synthetic crude oil reserves for the years 2013 through 2017 are projected to be $2,665 million, $2,726 million, $2,955 million, $2,132 million, and $425 million.

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

Net Production Sold

	North America			Africa			Europe	
	U.S.	Canada	Total	E.G.	Other	Total	Total	Grand Total
Year Ended December 31, 2012								
Liquid hydrocarbons (mbbld)[(a)]	107	—	107	36	42	78	97	282
Natural gas (mmcfd)[(b)(c)]	358	—	358	428	15	443	86	887
Synthetic crude oil (mbbld)	—	41	41	—	—	—	—	41
Total production sold (mboed)	167	41	208	108	44	152	111	471
Year Ended December 31, 2011								
Liquid hydrocarbons (mbbld)[(a)]	75	—	75	38	5	43	101	219
Natural gas (mmcfd)[(b)(c)]	326	—	326	443	—	443	81	850
Synthetic crude oil (mbbld)	—	38	38	—	—	—	—	38
Total production sold (mboed)	129	38	167	112				