MURPHY OIL CORP /DE
Form 10-K
February 28, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2013

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ________ to ________

Commission file number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**71-0361522**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
200 Peach Street, P.O. Box 7000,	
El Dorado, Arkansas	**71731-7000**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (870) 862-6411

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $1.00 Par Value	**New York Stock Exchange**
Series A Participating Cumulative Preferred Stock Purchase Rights	**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 x 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 x

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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x 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 x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. x

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

Large accelerated filer	x	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 x

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter (as of June 30, 2013) $9,733,180,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2014 was 183,181,954.

Documents incorporated by reference:

Portions of the Registrant s definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 14, 2014 have been incorporated by reference in Part III herein.

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MURPHY OIL CORPORATION

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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a worldwide oil and gas exploration and production company, with refining and marketing operations in the United Kingdom that are held for sale. The Company is in the process of transitioning from an integrated oil company to an enterprise entirely focused on oil and gas exploration and production activities. As used in this report, the terms Murphy, Murphy Oil, we, our, its and Company may refer to Murphy Oil Corporation or any one or more of its consolidated subsidiaries.

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation. It was reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation, and was reorganized in 1983 to operate primarily as a holding company of its various businesses. For reporting purposes, Murphy s exploration and production activities are subdivided into five geographic segments, including the United States, Canada, Malaysia, the Republic of the Congo and all other countries. Murphy s refining and marketing activities are now all located in the United Kingdom. As described further in this Form 10-K, Murphy has previously announced its intention to sell its U.K. downstream business. On August 30, 2013, the Company completed the separation of U.S. retail marketing operations with the spin-off of Murphy USA Inc. as a stand-alone company trading on the New York Stock Exchange under the ticker symbol MUSA . Additionally, Corporate activities include interest income, interest expense, foreign exchange effects and administrative costs not allocated to the segments. The Company s corporate headquarters are located in El Dorado, Arkansas.

The information appearing in the 2013 Annual Report to Security Holders (2013 Annual Report) is incorporated in this Form 10-K report as Exhibit 13 and is deemed to be filed as part of this Form 10-K report as indicated under Items 1, 2 and 7.

In addition to the following information about each business activity, data about Murphy s operations, properties and business segments, including revenues by class of products and financial information by geographic area, are provided on pages 25 through 46, F-18 and F-19, F-50 through F-58 and F-60 of this Form 10-K report and on pages 5 and 6 of the 2013 Annual Report.

At December 31, 2013, Murphy had 1,875 employees. Approximately 450 of these employees staff the Company s U.K. refining and marketing business. The separation of Murphy USA Inc. in 2013 reduced the Company s employee count by approximately 1,700 full-time and 6,300 part-time staff.

Interested parties may obtain the Company s public disclosures filed with the Securities and Exchange Commission (SEC), including Form 10-K, Form 10-Q, Form 8-K and other documents, by accessing the Investor Relations section of Murphy Oil Corporation s Web site at www.murphyoilcorp.com.

Exploration and Production

The Company s exploration and production business explores for and produces crude oil, natural gas and natural gas liquids worldwide. The Company s exploration and production management team in Houston, Texas, directs the Company s worldwide exploration and production activities. This business maintains upstream operating offices in other locations around the world, with the most significant of these including Calgary, Alberta and Kuala Lumpur, Malaysia.

During 2013, Murphy s principal exploration and production activities were conducted in the United States by wholly owned Murphy Exploration & Production Company USA (Murphy Expro USA), in Malaysia, Indonesia, Suriname, Australia, Brunei, Cameroon, Vietnam, Equatorial Guinea, Republic of the Congo, and the Kurdistan region of Iraq by wholly owned Murphy Exploration & Production Company International

(Murphy Expro International) and its subsidiaries, and in Western Canada and offshore Eastern Canada by wholly-owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries. Murphy s hydrocarbon production in 2013 was in the United States, Canada, Malaysia, the Republic of the Congo and the United Kingdom. MOCL owns a 5% undivided interest in Syncrude Canada Ltd. in northern Alberta, one of the world s largest producers of synthetic crude oil. In 2013 the Company sold all exploration and production assets in the United Kingdom. The results for these U.K. operations have been reported as discontinued operations in the consolidated financial statements for all periods presented. Unless otherwise indicated, all references to the Company s oil and gas production volumes and proved oil and gas reserves are net to the Company s working interest excluding applicable royalties.

Murphy s worldwide crude oil, condensate and natural gas liquids production in 2013 averaged 135,078 barrels per day, an increase of 20% compared to 2012, and the highest oil volumes produced by the Company over an annual period. The increase was primarily due to higher 2013 oil production in the Eagle Ford Shale area of South Texas. The Company s worldwide sales volume of natural gas averaged 424 million cubic feet (MMCF) per day in 2013, down 14% from 2012 levels. The reduction in natural gas sales volume in 2013 was primarily attributable to lower gas production in the Tupper area in Western Canada, where further development drilling was voluntarily curtailed due to low local natural gas sales prices, and in Malaysia at the Kikeh field where the third-party gas receiving facility had more downtime in 2013. Total worldwide 2013 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 205,719 barrels per day, an increase of 6% compared to 2012, and also a Company record for a single year.

Total production in 2014 is currently expected to average between 235,000 and 240,000 barrels of oil equivalent per day. The projected production increase of 14% to 17% in 2014 includes approximately a 23% to 26% increase in oil and liquids volumes. The overall anticipated production increase in 2014 is primarily related to higher oil volumes expected in the Eagle Ford Shale area as the Company continues its drilling program in the play. Additionally, Malaysian oil production is anticipated to rise in 2014 due to ramp-up of production in Blocks SK 309/311 following start-up of four new oil fields in the second half of 2013, full field start up at the Kakap-Gumusut field and new production at the Siakap North-Petai field. These higher oil volumes are expected to more than offset production declines in 2013 at other producing fields. Natural gas production is expected to decline slightly in 2014 as start up of a new field in the Gulf of Mexico and higher volumes in Malaysia do not fully offset the effects of production decline associated with continued voluntary curtailment of development drilling activities in the Tupper area in northeast British Columbia caused by historically depressed North American natural gas prices.

United States

In the United States, Murphy primarily has production of oil and/or natural gas from fields in the Eagle Ford Shale area of South Texas and in the deepwater Gulf of Mexico. The Company produced approximately 48,400 barrels of oil per day and 53 MMCF of natural gas per day in the U.S. in 2013. These amounts represented 36% of the Company s total worldwide oil and 13% of worldwide natural gas production volumes. During 2013, approximately 31% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico. Approximately two-thirds of Gulf of Mexico production in 2013 was derived from three fields, including Medusa, Front Runner and Thunder Hawk. The Company holds a 60% interest in Medusa in Mississippi Canyon Blocks 538/582, and 62.5% working interests in the Front Runner field in Green Canyon Blocks 338/339 and the Thunder Hawk field in Mississippi Canyon Block 734. Total daily production in the Gulf of Mexico in 2013 was 12,500 barrels of oil and 31 MMCF of natural gas. Total production in the Gulf of Mexico in 2014 is expected to increase to about 15,000 barrels of oil per day and approximately 42 MMCF per day of natural gas; the increase in 2014 is primarily related to the anticipated start-up of the Dalmatian field in DeSoto Canyon Blocks 4 and 48. The Company has a 70% working interest in the Dalmatian properties. At December 31, 2013, Murphy has total proved reserves for Gulf of Mexico fields of 29.1 million barrels of oil and 77 billion cubic feet of natural gas.

The Company has acquired rights to approximately 164 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and gas play. The Company currently has eight active drilling rigs and three hydraulic fracturing teams operating in the Eagle Ford in early 2014. Current plans are to drill approximately 170 wells in the play in 2014. The Company is concentrating drilling efforts in the areas of the Eagle Ford where oil is the primary hydrocarbon produced. Total 2013 oil and natural gas production in the Eagle Ford area was approximately 35,600 barrels per day and 21 MMCF per day, respectively. On a barrel of oil equivalent basis, Eagle Ford production accounted for 68% of total U.S. production volumes in 2013. Due to ongoing drilling and infrastructure development activities, 2014 production in the Eagle Ford Shale is expected to increase to approximately 53,000 barrels of oil per day and 24 MMCF of natural gas per day. At December 31, 2013, the Company s proved reserves in the Eagle Ford Shale area totaled 185.3 million barrels of oil and 104 billion cubic feet of natural gas. Total U.S. proved oil and natural gas reserves at December 31, 2013 were 214.7 million barrels and 185 billion cubic feet, respectively.

Canada

In Canada, the Company owns an interest in three significant non-operated assets the Hibernia and Terra Nova fields offshore Newfoundland in the Jeanne d Arc Basin and Syncrude Canada Ltd. in northern Alberta. In addition, the Company owns interests in one heavy oil area and two significant natural gas areas in the Western Canadian Sedimentary Basin (WCSB).

Murphy has a 6.5% working interest in Hibernia, while at Terra Nova the Company s working interest is 10.475%. Oil production in 2013 was about 5,600 barrels of oil per day at Hibernia and 3,500 barrels per day at Terra Nova. Hibernia production increased slightly in 2013 due to new wells brought on stream, while Terra Nova production was significantly higher in 2013 due to an extended period of downtime for maintenance during the second half of 2012. Oil production for 2014 at Hibernia and Terra Nova is anticipated to be approximately 5,000 barrels per day and 3,800 barrels per day, respectively. Total proved oil reserves at December 31, 2013 at Hibernia and Terra Nova were approximately 14.3 million barrels and 8.4 million barrels, respectively.

Murphy owns a 5% undivided interest in Syncrude Canada Ltd., a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets, which include three coking units, to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Production in 2013 was about 12,900 net barrels of synthetic crude oil per day and is expected to average about 13,700 barrels per day in 2014. Total proved reserves for Syncrude at year-end 2013 were 117 million barrels.

Daily production in 2013 in the WCSB averaged 9,200 barrels of mostly heavy oil and 175 MMCF of natural gas. The Company has 133 thousand net acres of mineral rights in the Montney area, described as Tupper and Tupper West. Natural gas production commenced at Tupper in December 2008, while Tupper West production started up in February 2011. The Company has 326 thousand net acres of mineral rights in the Seal area located in the Peace River oil sands area of Northwest Alberta. Oil and natural gas daily production for 2014 in Western Canada, excluding Syncrude, is expected to be about 9,000 barrels and 147 MMCF, respectively. The decrease in natural gas volumes in 2014 is primarily the result of natural well decline due to continued curtailment of development drilling at Tupper West and Tupper associated with depressed North American natural gas prices. Total WCSB proved oil and natural gas reserves at December 31, 2013, excluding Syncrude, were 16 million barrels and 549 billion cubic feet, respectively.

Malaysia

In Malaysia, the Company has majority interests in seven separate production sharing contracts (PSCs). The Company serves as the operator of all these areas other than the unitized Kakap-Gumusut field. The production sharing contracts cover approximately 2.87 million gross acres. Murphy has an 85% interest in oil and natural gas discoveries made in two shallow-water blocks, SK 309 and SK 311, offshore Sarawak. The Company brought on production from five new fields Serendah, Patricia, South Acis, Permas and Merapuh during the second half of 2013. These fields are producing through a series of new offshore platforms and pipelines tying back to the Company s existing infrastructure. About 11,000 barrels of oil per day were produced in 2013 at

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Blocks SK 309/311, almost evenly split between the West Patricia field and other Sarawak fields. Oil production in 2014 at fields in Blocks SK 309/311 is anticipated to total about 21,900 barrels of oil per day, with the increase associated with a full year of production at the new Sarawak oil fields. The Company has a gas sales contract for the Sarawak area with PETRONAS, the Malaysian state-owned oil company, and has an ongoing multi-phase development plan for several natural gas discoveries on these blocks. The gas sales contract, including an extension option exercised in 2012, allows for gross sales volumes of up to 250 MMCF per day through September 2021. Total net natural gas sales volume offshore Sarawak was about 165 MMCF per day during 2013 (gross 239 MMCF per day). Sarawak net natural gas sales volumes are anticipated to be approximately 159 MMCF per day in 2014, with the reduction primarily attributable to an entitlement change to the Company. Total proved reserves of oil and natural gas at December 31, 2013 for Blocks SK 309/311 were 23 million barrels and 331 billion cubic feet, respectively.

The Company made a major discovery at the Kikeh field in deepwater Block K, offshore Sabah, Malaysia, in 2002 and added another discovery at Kakap in 2004. An additional discovery was made in Block K at Siakap North-Petai in 2009. In 2006, the Company relinquished a portion of Block K and was granted a 60% interest in an extension of a portion of Block K. In 2011, the Company relinquished the remainder of Block K except for the discovered fields, which include Kikeh, Kakap-Gumusut and Siakap North-Petai. Total gross acreage held by the Company in Block K as of December 31, 2013 was 80,000 acres. Production volumes at Kikeh averaged 40,400 barrels of oil per day during 2013. Oil production at Kikeh is anticipated to average approximately 29,000 barrels per day in 2014. The oil reduction in 2014 is primarily attributable to planned downtime for equipment installation to allow Siakap North-Petai volumes to be produced through the Kikeh facility. The Company has a Kikeh field natural gas sales contract with PETRONAS that calls for gross sales volumes of up to 120 MMCF per day. Gas production at Kikeh will continue until the earlier of lack of available commercial quantities of Kikeh associated gas reserves or expiry of the Block K production sharing contract. Natural gas production at Kikeh in 2013 totaled approximately 30 MMCF per day. Daily gas production in 2014 at Kikeh is expected to average about 40 MMCF per day. The 2014 gas increase at Kikeh is due to less anticipated downtime at the onshore receiving facility owned by PETRONAS. The Kakap-Gumusut field in Block K is operated by another company. The Kakap field is being jointly developed with the Gumusut field owned by others and Murphy holds a 14% working interest in the unitized development. Early production began in late 2012 at Kakap-Gumusut, via a temporary tie-back to the Kikeh production facility. Kakap-Gumusut development activities continued during 2013. The primary Kakap-Gumusut production facility is expected to be completed in 2014, whereby oil production can be ramped up to a significantly higher volume. Kakap-Gumusut oil production in 2013 totaled 2,400 net barrels of oil per day. Kakap-Gumusut production in 2014 is expected to average 8,100 barrels of oil per day. The Siakap North-Petai oil discovery is being developed as a unitized area operated by Murphy, with a tie-back to the Kikeh field. Production is expected to begin in 2014 at Siakap North-Petai with a daily average anticipated of 7,400 barrels of oil and 5 MMCF of gas during the year. Total proved reserves booked in Block K as of year-end 2013 were 102 million barrels of oil and 75 billion cubic feet of natural gas.

The Company also has an interest in deepwater Block H offshore Sabah. In early 2007, the Company announced a significant natural gas discovery at the Rotan well in Block H. Since 2007, the Company has followed up Rotan with several other nearby discoveries. In March 2008, the Company renewed the contract for Block H at a 60% interest while retaining 80% interest in the Rotan and Biris discoveries. In 2011, the Company relinquished 30% of Block H, but retained all discovered fields. Total gross acreage held by the Company at year-end 2013 in Block H was 1.40 million acres. In early 2014, PETRONAS and the Company sanctioned a Floating Liquefied Natural Gas project for Block H, and agreed terms for sales of natural gas to be produced with prices tied to an oil index.

The Company has a 60% interest in a gas holding area covering approximately 2,000 gross acres in Block P. This interest can be retained until January 2018. The remainder of Block P was relinquished in early 2013.

In May 2013, the Company acquired an 85% working interest in shallow-water Malaysia Block SK 314A. The production sharing contract covers a three-year exploration period. Total gross acreage for this block is 1.12 million acres. The Company s 15% partner in this concession is being carried by Murphy through the minimum work program. Geophysical studies were performed during 2013 and the first exploration wells are planned in 2015.

Murphy has a 75% interest in gas holding agreements for Kenarong and Pertang discoveries made in Block PM 311 located offshore peninsular Malaysia. Development options are being studied for these discoveries.

Australia

The Company holds six exploration permits in Australia and serves as operator of four of them. A 40% interest in Block AC/P36 in the Browse Basin offshore northwestern Australia was acquired in 2007 and one unsuccessful well has been drilled. The Company renewed the exploration permit for an additional five years and in that process relinquished 50% of the gross acreage; the license now covers 482 thousand gross acres. Murphy increased its working interest in the remaining acreage to 100% in 2012 and subsequently farmed out a 50% working interest and operatorship.

Block NT/P80 in the Bonaparte Basin, offshore northwestern Australia, was acquired in June 2009 and covers approximately 1.20 million gross acres. The Company s working interest is 70% and it acquired 3D seismic data over this block during 2013.

In May 2012, Murphy was awarded permit WA-476-P in the Carnarvon Basin, offshore Western Australia. The Company holds 100% working interest in the permit which covers 177,000 gross acres. The work commitment includes seismic data reprocessing and geophysical work.

In August 2012, Murphy was awarded permit WA-481-P in the Perth Basin, offshore Western Australia. The permit covers approximately 4.30 million gross acres, with water depths ranging from 20 to 300 meters. The Company holds a 40% working interest. The work commitment calls for 2D and 3D seismic acquisition and processing, geophysical work and three exploration wells.

In November 2012, Murphy acquired a 20% non-operated working interest in permit WA-408-P in the Browse Basin. The permit comprises approximately 417,000 gross acres. Two wells were drilled on the license in 2013. The first well found hydrocarbon but was deemed unsuccessful and was written off to expense. The second well was also unsuccessful.

In October 2013, the Company was awarded permit EPP 43 in the Ceduna Basin, offshore South Australia. The Company operates the concession and holds a 50% working interest in the permit which covers approximately 4.08 million gross acres. The exploration permit covers six years and requires commitments for 2D and 3D seismic.

Indonesia

The Company currently has interests in four exploration licenses in Indonesia and serves as operator of all these concessions. In November 2008, Murphy entered into a production sharing contract in the Semai II block offshore West Papua. The Company has a 28.3% interest in the block which covers about 543 thousand gross acres after a required partial relinquishment of acreage during 2012. The permit calls for a 3D seismic program and three exploration wells. The 3D seismic was acquired in 2010, while the first exploration well in the Semai II block was drilled in early 2011 and was unsuccessful. The second and third exploration wells are planned for 2014.

In December 2010, Murphy entered into a production sharing contract in the Wokam II block offshore West Papua, Moluccas and Papua. Murphy has a 100% interest in the block which covers 918 thousand gross acres. The three-year work commitment calls for seismic acquisition and processing, which the Company completed in 2013.

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In November 2011, the Company acquired a 100% interest in a production sharing contract in the Semai IV block offshore West Papua. The concession includes 873 thousand gross acres. The agreement calls for work commitments of seismic acquisition and processing which are currently part of the Company s 2014 exploration plan.

In May 2008, the Company entered into a production sharing contract at a 100% interest in the South Barito block in south Kalimantan on the island of Borneo. Following contractually mandated acreage relinquishment in 2012, the block now covers approximately 745 thousand gross acres. The contract permits a six-year exploration term with an optional four-year extension. The Company currently anticipates exiting this block in 2014.

Brunei

In late 2010, the Company entered into two production sharing agreements for properties offshore Brunei. The Company has a 5% working interest in Block CA-1 and a 30% working interest in Block CA-2. The CA-1 and CA-2 blocks cover 1.44 million and 1.49 million gross acres, respectively. Three successful wells were drilled in Block CA-1 in 2012 and three wells were successfully drilled in Block CA-2 in 2013. The partnership group is evaluating development options for Block CA-2.

Vietnam

In November 2012, the Company signed a production sharing contract with Vietnam National Oil and Gas Group and PetroVietnam Exploration Production Company, whereby it acquired 65% interest and operatorship of Blocks 144 and 145. The blocks cover approximately 4.42 million gross acres and are located in the outer Phu Khanh Basin. The Company licensed existing 2D seismic for these blocks in 2013.

In late 2012, the Company was granted Vietnam s government approval to acquire a 60% working interest and operatorship of Block 11-2/11 and the production sharing contract was signed in June 2013. The block covers 677 thousand gross acres. The Company acquired 3D seismic and performed other geological and geophysical studies in this block in 2013.

In early 2014, the Company farmed into Block 13-03. The Company has a 20% working interest in this concession which covers 853,000 gross acres. Murphy is currently scheduled to spud a well in the block in mid 2014.

Suriname

In December 2011, Murphy signed a production sharing contract with Suriname s state oil company, Staatsolie Maatschappij Suriname N.V. (Staatsolie), whereby it acquired a 100% working interest and operatorship of Block 48 offshore Suriname. The block encompasses 794 thousand gross acres with water depths ranging from 1,000 to 3,000 meters. The 30-year contract is divided into an exploration period and one or more development and production periods, and may be extended with mutual agreement of Murphy and Staatsolie. There are three phases of the exploration period, with each divided into two-year terms, thereby allowing the Company to withdraw from the contract or enter into the next phase. Minimum work obligations vary during each exploration phase and may require either seismic data acquisition or drilling of an exploratory well. Staatsolie has the right to join in the development and production of each commercial field within the contract area with up to a 20% participation. In early 2014, Murphy farmed out a portion of its working interest in Block 48, thereby reducing its interest from 100% to 50%.

Cameroon

In October 2011, Murphy was granted government approval to acquire a 50% working interest and operatorship of the Ntem concession. The working interest was acquired through a farm-out agreement of the existing production sharing contract. The Ntem block, situated in the Douala Basin offshore Cameroon, encompasses

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573 thousand gross acres, with water depths ranging from 300 to 1,900 meters. The concession was in force majeure until January 2014. With force majeure lifted, there are 15 months of the first renewal period remaining which can be extended for a further two years under the second renewal period option in the contract. Each of the renewal periods requires a minimum work obligation involving the drilling of exploratory wells. The Company spud a well on the Ntem prospect in February 2014.

In 2012, Murphy acquired a 50% non-operated interest in the Elombo production sharing contract, immediately adjacent to the Ntem concession. The Elombo block, situated in the Douala Basin offshore Cameroon, between the shoreline and the Ntem block, encompasses 594 thousand gross acres with water depths ranging up to 1,100 meters. The initial exploration period was for three years and was scheduled to end in March 2013. Prior to the end of the initial period the Company drilled a shallow well which was unsuccessful. The initial exploration period was extended for two years through March 2015 with an obligation for one well. The exploration period may be extended one more time for an additional two years with a further one-well obligation. Murphy drilled an unsuccessful deepwater well in the block in 2013 as part of the obligations under the agreement.

Equatorial Guinea

In December 2012, Murphy signed a production sharing contract for block W offshore Equatorial Guinea. Murphy has a 45% working interest and operates the block. The government ratified the contract early in 2013. The block is located offshore mainland Equatorial Guinea and encompasses 557 thousand gross acres with water depths ranging from 60 to 2,000 meters. The initial exploration period of five years is divided into two sub-periods, a first sub-period of three years and a second sub-period of two years. The first sub-period may be extended one year and with this extension is the obligation to drill one well. Entering the second sub-period has the obligation to drill an additional well. In early 2014, Murphy completed acquisition of new 3D seismic over the entire block. Using the available seismic data, the Company is evaluating the potential for drilling.

Republic of the Congo

The Company formerly had interests in Production Sharing Agreements (PSA) covering two offshore blocks in Republic of the Congo Mer Profonde Sud (MPS) and Mer Profonde Nord (MPN). In 2005, Murphy made an oil discovery at Azurite Marine #1 in the southern block, MPS. Total oil production in 2013 averaged 1,000 barrels per day at Azurite for the Company s 50% interest. The field was shutdown and ceased production in the fourth quarter of 2013 and abandonment operations were well advanced in early 2014. Abandonment and other exit charges of $82.5 million were recorded in the fourth quarter of 2013 associated with the earlier than anticipated shutdown of the Azurite field. The MPN block exploration license expired on December 30, 2012 and MPS block exploration license expired in March 2013. Murphy will relinquish the Azurite field upon completion of abandonment in 2014.

Iraq

In late 2010, the Company finalized an agreement with the Kurdistan Regional Government (KRG) in Iraq to acquire an interest in the Central Dohuk block. The Company operated and held a 50% interest in the block. The Central Dohuk block covered approximately 153 thousand gross acres and is located in the Dohuk area of the Kurdistan region in Iraq. The Company shot seismic in 2011 and drilled an unsuccessful exploration well in 2012. The Company relinquished this exploration license during 2013.

United Kingdom Discontinued Operations

Murphy produced oil and natural gas in the United Kingdom sector of the North Sea for many years. In 2013, Murphy sold all of its oil and gas properties in the U.K. with an after-tax gain of $216.1 million on the sale. Total 2013 production in the U.K. on a full-year basis amounted to about 600 barrels of oil per day and 1 MMCF of natural gas per day. The Company has accounted for U.K. oil and gas activities as discontinued operations for all periods presented.

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Ecuador Discontinued Operations

Murphy sold its 20% working interest in Block 16, Ecuador in March 2009. The Company has accounted for all Ecuador operations as discontinued operations. In October 2007, the government of Ecuador passed a law that increased its share of revenue for sales prices that exceed a base price (about $23.36 per barrel at December 31, 2008) from 50% to 99%. The government had previously enacted a 50% revenue sharing rate in April 2006. The Company initiated arbitration proceedings against the government in one international jurisdiction claiming that the government did not have the right under the contract to enact the revenue sharing provision. In 2010, the arbitration panel determined that it lacked jurisdiction over the claim due to technicalities. The arbitration was refiled in 2011 under a different international jurisdiction and present activities involve preparation for a hearing on the merits of the filing. The arbitration proceeding is likely to take many months to reach conclusion. The Company s total claim in the arbitration process is approximately $118 million.

Proved Reserves

Total proved oil and natural gas reserves as of December 31, 2013 are presented in the following table.

	Proved Reserves		
	Oil	Synthetic Oil	Natural Gas
	(millions of barrels)		(billions of cubic feet)
Proved Developed Reserves:			
United States	88.9		112.6
Canada	31.6	117.0	384.0
Malaysia	66.6		289.6
Total proved developed reserves	187.1	117.0	786.2
Proved Undeveloped Reserves:			
United States	125.8		72.4
Canada	7.2		178.8
Malaysia	58.5		116.2
Total proved undeveloped reserves	191.5		367.4
Total proved reserves	378.6	117.0	1,153.6

Murphy Oil s proved undeveloped reserves increased during 2013 as presented in the table that follows:

(Millions of oil equivalent barrels)	
Proved undeveloped reserves:	
Beginning of year	218.9
Revisions of previous estimates	49.3
Extension and discoveries	54.1
Conversion to proved developed reserves	(52.2)
Sales of properties	(17.4)
End of year	252.7

Murphy s total proved undeveloped reserves at December 31, 2013 increased 33.8 million barrels of oil equivalent (MMBOE) from a year earlier. The conversion of non-proved reserves to newly reported proved undeveloped reserves reported in the table as extensions and discoveries during 2013 was predominantly attributable to drilling in the Eagle Ford Shale area of South Texas as this area had active development work ongoing during the year. The majority of proved undeveloped reserves additions associated with revisions of previous estimates was the result of development drilling and/or well performance at the Eagle Ford Shale, the Kikeh field in Malaysia and offshore

Eastern Canada. The majority of the proved undeveloped reserves migration to the proved developed category occurred in the Eagle Ford Shale. The Company sold all of its U.K. oil and gas properties during the first half of 2013 which led to a reduction of proved undeveloped reserves of 17.4 million barrels equivalent during the year. The Company spent approximately $1.2 billion in 2013 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend about $1.1 billion in 2014, $1.0 billion in 2015 and $1.1 billion in 2016 to move currently undeveloped proved reserves to the developed category. The anticipated level of spend in 2014 includes significant drilling in several locations, primarily in the Eagle Ford Shale area. In computing MMBOE, natural gas is converted to equivalent barrels of oil using a ratio of six thousand cubic feet (MCF) to one barrel of oil.

At December 31, 2013, proved reserves are included for several development projects, including oil developments at the Eagle Ford Shale in South Texas and the Kakap-Gumusut, Kikeh and Siakap North-Petai fields, offshore Sabah, Malaysia as well as a natural gas development offshore Sarawak, Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2013 were approximately 253 MMBOE, which is 37% of the Company s total proved reserves. Certain of these development projects have proved undeveloped reserves that will take more than five years to bring to production. Three such projects have significant levels of such proved undeveloped reserves. The Company operates a deepwater field in the Gulf of Mexico that has two undeveloped locations that exceed this five-year window. Total reserves associated with the two wells amount to less than 1% of the Company s total proved reserves at year-end 2013. The development of certain of this field s reserves stretches beyond five years due to limited well slots available on the production platform, thus making it necessary to wait for depletion of other wells prior to initiating further development of these two locations. The Kakap-Gumusut field oil development project has undeveloped proved reserves that make up 5% of the Company s total proved reserves at year-end 2013. This non-operated project has taken longer than five years to develop due to long lead-time equipment required to complete the development process in the deep waters offshore Sabah Malaysia. Full field start up is expected in 2014. The third project that will take more than five years to develop is offshore Malaysia and makes up approximately 2% of the Company s total proved reserves at year-end 2013. This project is an extension of the Sarawak natural gas project and should be on production in 2014 once current project production volumes decline.

Murphy Oil s Reserves Processes and Policies

The Company employs a Manager of Corporate Reserves (Manager) who is independent of the Company s oil and gas management. The Manager reports to a Vice President of Murphy Oil Corporation, who in turn reports directly to the President and Chief Executive Officer of Murphy Oil. The Manager makes presentations to the Board of Directors periodically about the Company s reserves. The Manager reviews and discusses reserves estimates directly with the Company s reservoir engineering staff in order to make every effort to ensure compliance with the rules and regulations of the SEC and industry. The Manager coordinates and oversees reserves audits. These audits are performed annually and target coverage of approximately one-third of Company reserves each year. The audits are performed by the Manager and qualified engineering staff from areas of the Company other than the area being audited. The Manager may also utilize qualified independent reserves consultants to assist with the internal audits or to perform separate audits as considered appropriate.

Each significant exploration and production office maintains one or more Qualified Reserve Estimators (QRE) on staff. The QRE is responsible for estimating and evaluating reserves and other reserves information for his or her assigned area. The QRE may personally make the estimates and evaluations of reserves or may supervise and approve the estimation and evaluation thereof by others. A QRE is professionally qualified to perform these reserves estimates due to having sufficient educational background, professional training and professional experience to enable him or her to exercise prudent professional judgment. Normally, this requires a minimum of three years practical experience in petroleum engineering or petroleum production geology, with at least one year of such experience being in the estimation and evaluation of reserves, and either a bachelors or advanced degree in petroleum engineering, geology or other discipline of engineering or physical science from a college or university of recognized stature, or the equivalent thereof from an appropriate government authority or professional organization.

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Larger offices of the Company also employ a Regional Reserves Coordinator (RRC) who supervises the local QREs. The RRC is usually a senior QRE that has the primary responsibility for coordinating and submitting reserves information to senior management.

The Company s QREs maintain files containing pertinent data regarding each significant reservoir. Each file includes sufficient data to support the calculations or analogies used to develop the values. Examples of data included in the file, as appropriate, include: production histories; pertinent drilling and workover histories; bottom hole pressure data; volumetric, material balance, analogy or other pertinent reserve estimation data; production performance curves; narrative descriptions of the methods and logic used to determine reserves values; maps and logs; and a signed copy of the conclusion of the QRE stating, that in their opinion, the reserves have been calculated, reviewed, documented and reported in compliance with the regulations and guidelines contained in the reserves training manual. The Company s reserves are maintained in an industry recognized reservoir engineering software system, which has adequate access controls to avoid the possibility of improper manipulation of data. When reserves calculations are completed by QREs and appropriately reviewed by RRCs and the Manager, the conclusions are reviewed and discussed with the head of the Company s exploration and production business and other senior management as appropriate. The Company s Controller s department is responsible for preparing and filing reserves schedules within Form 10-K.

Murphy provides annual training to all company reserves estimators to ensure SEC requirements associated with reserves estimation and associated Form 10-K reporting are fulfilled. The training includes materials provided to each participant that outlines the latest guidance from the SEC as well as best practices for many engineering and geologic matters related to reserves estimation.

Qualifications of Manager of Corporate Reserves

The Company believes that it has qualified employees preparing oil and gas reserves estimates. Mr. F. Michael Lasswell serves as Corporate Reserves Manager after joining the Company in 2012. Prior to joining Murphy, Mr. Lasswell was employed as a Regional Coordinator of reserves at a major integrated oil company. He worked in several capacities in the reservoir engineering department with the oil company from 2002 to 2012. Mr. Lasswell earned a Bachelors of Science degree in Civil Engineering and a Masters of Science degree in Geotechnical Engineering from Brigham Young University. Mr. Lasswell has experience working in the reservoir engineering field in numerous areas of the world, including the North Sea, the U.S. Arctic, the Middle East and Asia Pacific. He serves on the Society of Petroleum Engineers (SPE) Oil and Gas Reserves Committee (OGRC) and is also co-author of a paper on the Recognition of Reserves which was published by the SPE. Mr. Lasswell has also attended numerous industry training courses.

More information regarding Murphy s estimated quantities of proved oil and gas reserves for the last three years are presented by geographic area on pages F-52 through F-55 of this Form 10-K report. Murphy has not filed and is not required to file any estimates of its total proved oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated proved reserves of such properties are determined.

Crude oil, condensate and gas liquids production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the seven years ended December 31, 2013 are shown on page 5 of the 2013 Annual Report. In 2013, the Company s production of oil and natural gas represented approximately 0.1% of worldwide totals.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed beginning on page 32 of this Form 10-K report. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of oil using a ratio of six MCF of natural gas to one barrel of oil.

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Supplemental disclosures relating to oil and gas producing activities are reported on pages F-50 through F-60 of this Form 10-K report.

At December 31, 2013, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres attributable to Murphy s interest.

	Developed		Undeveloped		Total	
Area (Thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States Onshore	83	70	96	89	179	159
Gulf of Mexico	12	5	1,040	651	1,052	656
Alaska	4	1	8		12	1
Total United States	99	76	1,144	740	1,243	816
Canada Onshore, excluding oil sands	78	78	739	578	817	656
Offshore	105	9	43	2	148	11
Oil sands Syncrude	96	5	160	8	256	13
Total Canada	279	92	942	588	1,221	680
Malaysia	290	239	2,582	1,847	2,872	2,086
Australia			10,666	5,102	10,666	5,102
Brunei			2,934	519	2,934	519
Indonesia			3,079	2,690	3,079	2,690
Vietnam			5,098	3,280	5,098	3,280
Cameroon			1,167	584	1,167	584
Equatorial Guinea			557	251	557	251
Suriname			794	636	794	636
Republic of the Congo			11	6	11	6
Iraq			153	76	153	76
Spain			36	6	36	6
Totals	668	407	29,163	16,325	29,831	16,732

Certain acreage held by the Company will expire in the next three years. Scheduled expirations in 2014 include 745 thousand net acres in South Barito Indonesia; 123 thousand net acres in Semai II Indonesia; 38 thousand net acres in Semai IV Indonesia; 196 thousand net acres in the United States; 53 thousand net acres in Western Canada; 76 thousand net acres in the Kurdistan region of Iraq; 9 thousand net acres in SK Block 309 in Malaysia; and 36 thousand net acres in Block PM 311 Malaysia. In 2015, scheduled expiring acreage includes 57 thousand net acres in SK Blocks 309 and 311 in Malaysia; 420 thousand net acres in NT/P80 Australia; 42 thousand net acres in WA-408-P Australia; 281 thousand net acres in Western Canada; 53 thousand net acres in the United States; 146 thousand net acres in Cameroon; and 636 thousand net acres in Block 48 Suriname. Scheduled acreage expirations in 2016 include 837 thousand net acres in Block H in Malaysia; 957 thousand net acres in Block SK 314A in Malaysia; 734 thousand net acres in Wokam II Block in Indonesia; 575 thousand net acres in Blocks 144 and 145 in Vietnam; 81 thousand net acres in Block 11-2/11 in Vietnam; 98 thousand net acres in the United States; and 93 thousand net acres in Western Canada.

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As used in the three tables that follow, gross wells are the total wells in which all or part of the working interest is owned by Murphy, and net wells are the total of the Company s fractional working interests in gross wells expressed as the equivalent number of wholly owned wells. An exploratory well is drilled to find and produce crude oil or natural gas in an unproved area and includes delineation wells which target a new reservoir in a field known to be productive or to extend a known reservoir beyond the proved area. A development well is drilled within the proved area of an oil or natural gas reservoir that is known to be productive.

The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2013.

	Oil Wells		Gas Wells	
Country	Gross	Net	Gross	Net
United States	384	320	23	16
Canada	423	380	178	178
Malaysia	60	49	46	39
Totals	867	749	247	233

Murphy s net wells drilled in the last three years are shown in the following table.

	United States		Canada		Malaysia		Other		Totals	
	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry
2013										
Exploratory	**15.2**	**0.4**		**1.0**			**0.9**	**1.4**	**16.1**	**2.8**
Development	**161.2**		**22.0**	**19.0**	**16.3**				**199.5**	**19.0**
2012										
Exploratory	15.2	0.1		1.0	2.8	0.8		2.9	18.0	4.8
Development	92.2		106.5	21.5	20.5				219.2	21.5
2011										
Exploratory	17.9		1.0	4.9	0.9			2.3	19.8	7.2
Development	14.3	0.8	117.5	6.0	12.8		0.5		145.1	6.8

The Canadian dry development wells shown above are stratigraphic wells used to obtain information about Seal area heavy oil reservoirs. These wells will not be used to produce oil.

Murphy s drilling wells in progress at December 31, 2013 are shown in the following table. The year-end well count includes wells awaiting various completion operations. The U.S. net wells included below are essentially all located in the Eagle Ford Shale area of South Texas.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States			88	74.7	88	74.7
Canada			3	3.0	3	3.0
Totals			91	77.7	91	77.7

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Refining and Marketing Discontinued Operations

The Company completed the separation of its former retail marketing business in the United States during the year. On August 30, 2013, the Company spun-off the U.S. downstream business through a distribution of 100% of the shares of this Company to shareholders of Murphy Oil. The new stand-alone, publicly owned company, which is now known as Murphy USA Inc. (MUSA), is listed on the New York Stock Exchange under the ticker symbol MUSA .

The Company has also announced its intention to sell its refining and marketing (downstream) business in the United Kingdom. The sale of the U.K. downstream business is subject to inherent risks and uncertainties. Factors that could cause this forecasted event not to occur are described in Item 1A on page 18 of this Form 10-K report. All of the results of the U.S. and U.K. downstream businesses have been reported as discontinued operations for all periods presented in this report.

Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary, owns 100% interest in a refinery at Milford Haven, Pembrokeshire, Wales. The refinery is located on a 938 acre site owned by the Company; 430 acres are used by the refinery and the remainder is rented for agricultural use. The Milford Haven refinery was shut down for a plant-wide turnaround in early 2010. During the downtime, the Company completed an expansion project that increased the plant s crude oil throughput capacity from 108,000 barrels per day to 135,000 barrels per day. During 2013, the Milford Haven plant processed an average of 122,930 barrels of crude oil per day.

Refinery capacities at the Milford Haven, Wales facility at December 31, 2013 were as follows:

Crude capacity barrels per stream day	135,000
Process capacity barrels per stream day	
Vacuum distillation	55,000
Catalytic cracking fresh feed	37,750
Naphtha hydrotreating/reforming	21,100
Distillate hydrotreating	77,700
Isomerization	15,800
Production capacity barrels per stream day	
Alkylation	6,300
Crude oil and product storage capacity barrels	8,832,200

At the end of 2013, Murco distributed refined products in the United Kingdom from the wholly-owned Milford Haven refinery, three wholly owned terminals supplied by rail, six terminals owned by others where products are received in exchange for deliveries from the Company s terminals and eight terminals owned by others where products are purchased for delivery. At December 31, 2013, there were 229 Company stations, all of which were branded MURCO. The Company owns the freehold on 149 of the sites and leases the remainder. The Company also supplied 227 MURCO branded dealer stations at year-end 2013.

At December 31, 2013, MURCO owned approximately 8.3% of the refining capacity in the United Kingdom. MURCO s retail fuel sales represented 2.4% of the total U.K. market share in 2013.

A statistical summary of key U.K. operating and financial indicators for each of the seven years ended December 31, 2013 are reported on page 6 of the 2013 Annual Report.

Environmental

Murphy s businesses are subject to various U.S. federal, state and local environmental, health and safety laws and regulations, and are also subject to similar laws and regulations in other countries in which it operates. These regulatory requirements continue to change and increase in number and complexity, and the requirements govern the manner in which the company conducts its operations and the products it sells. The Company anticipates more environmental regulations in the future in the countries where it has operations.

Further information on environmental matters and their impact on Murphy are contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 42 through 46.

Web site Access to SEC Reports

Murphy Oil s internet Web site address is http://www.murphyoilcorp.com. Information contained on the Company s Web site is not part of this report on Form 10-K.

The Company s Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on Murphy s Web site, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. You may also access these reports at the SEC s Web site at *http://www.sec.gov*.

Item 1A. RISK FACTORS

Murphy Oil s businesses operate in highly competitive environments, which could adversely affect it in many ways, including its profitability, its ability to grow, and its ability to manage its businesses.

Murphy operates in the oil and gas industry and experiences intense competition from other oil and gas companies, which include state-owned foreign oil companies, major integrated oil companies, independent producers of oil and natural gas and independent refining and marketing companies. Virtually all of the state-owned and major integrated oil companies and many of the independent producers and refiners that compete with the Company have substantially greater resources than Murphy. In addition, the oil industry as a whole competes with other industries in supplying energy requirements around the world. Murphy competes, among other things, for valuable acreage positions, exploration licenses, drilling equipment and human resources.

If Murphy cannot replace its oil and natural gas reserves, it may not be able to sustain or grow its business.

Murphy continually depletes its oil and natural gas reserves as production occurs. In order to sustain and grow its business, the Company must successfully replace the crude oil and natural gas it produces with additional reserves. Therefore, it must create and maintain a portfolio of good prospects for future reserves additions and production by obtaining rights to explore for, develop and produce hydrocarbons in promising areas. In addition, it must find, develop and produce and/or purchase reserves at a competitive cost structure to be successful in the long-term. Murphy s ability to operate profitably in the exploration and production segments of its business, therefore, is dependent on its ability to find, develop and produce and/or purchase oil and natural gas reserves at costs that are less than the realized sales price for these products and at costs competitive with competing companies in the industry.

Murphy s proved reserves are based on the professional judgment of its engineers and may be subject to revision.

Proved oil and natural gas reserves included in this report on pages F-52 through F-55 have been prepared by qualified Company personnel or qualified independent engineers based on an unweighted average of oil and natural gas prices in effect at the beginning of each month as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground oil and natural gas reservoirs. Estimates of economically recoverable oil and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods. Under existing SEC rules, reported proved reserves must be reasonably certain of recovery in future periods.

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Murphy s actual future oil and natural gas production may vary substantially from its reported quantity of proved reserves due to a number of factors, including:

Oil and natural gas prices which are materially different than prices used to compute proved reserves

Operating and/or capital costs which are materially different than those assumed to compute proved reserves

Future reservoir performance which is materially different from models used to compute proved reserves, and

Governmental regulations or actions which materially change operations of a field.

The Company s proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2013, approximately 39% of the Company s proved oil reserves and 32% of proved natural gas reserves are undeveloped. The ability of the Company to reclassify these undeveloped proved reserves to the proved developed classification is generally dependent on the successful completion of one or more operations, which might include further development drilling, construction of facilities or pipelines, and well workovers.

The discounted future net revenues from our proved reserves as reported on pages F-59 and F-60 should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based on an unweighted average of the oil and natural gas prices in effect at the beginning of each month during the year. Actual future prices and costs may be materially higher or lower than those used in the reserves computations. In addition, the 10 percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the crude oil and natural gas business in general.

Volatility in the global prices of oil, natural gas and petroleum products significantly affects the Company s operating results.

Among the most significant variables affecting the Company s results of operations are the sales prices for crude oil and natural gas that it produces. West Texas Intermediate (WTI) crude oil prices averaged about $98 per barrel in 2013, compared to $94 per barrel in 2012 and $95 per barrel in 2011. Although WTI average prices in 2013 were not significantly different than the two previous years, prices can be quite volatile as demonstrated by the range of high and low prices during 2013 of about $110 per barrel and $87 per barrel, respectively. The average NYMEX natural gas sales prices were $3.73 per thousand cubic feet (MCF) in 2013, up from $2.83 per MCF in 2012, but lower than the $4.03 per MCF average in 2011. This relatively low price for natural gas hurt the Company s profits in North America during the three years ended December 31, 2013. As demonstrated in 2011 through 2013, the sales prices for oil and natural gas can be significantly different in U.S. markets compared to markets in foreign locations. Certain of the Company s crude oil production is heavy and more sour than WTI quality crude; therefore, this crude oil usually sells at a discount to WTI and other light and sweet crude oils. In addition, the sales prices for heavy and sour crude oils do not always move in relation to price changes for WTI and lighter/sweeter crude oils. Certain crude oils produced by the Company, including certain U.S. and Canadian crude oils and all crude oil produced in Malaysia, generally price off other oil indices than WTI, and these indices are influenced by different supply and demand forces than those that affect the U.S. WTI prices. The most common crude oil indices used to price the Company s crude include Louisiana Light Sweet (LLS), Brent and Malaysian crude oil indices. Certain natural gas production offshore Sarawak have been sold in recent years at a premium to average North American natural gas prices due to pricing structures built into the sales contracts. Associated natural gas produced at fields in Block K offshore Sabah are sold at heavily discounted prices compared to North American gas prices as stipulated in the sales contract. The Company cannot predict how changes in the sales prices of oil and natural gas will affect its results of operations in future periods. The Company often seeks to hedge a portion of its exposure to the effects of changing prices of crude oil and natural gas by purchasing forwards, swaps and other forms of derivative contracts.

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Exploration drilling results can significantly affect the Company s operating results.

The Company generally drills numerous wildcat wells each year which subjects its exploration and production operating results to significant exposure to dry holes expense, which have adverse effects on, and create volatility for, the Company s net income. In 2013, significant wildcat wells were primarily drilled offshore Cameroon, Brunei, Australia and in the Gulf of Mexico. The Company s 2014 planned exploratory drilling program includes wells offshore in the Gulf of Mexico, Cameroon, Brunei, Australia, Vietnam and Indonesia.

Potential federal or state regulations regarding hydraulic fracturing could increase our costs and/or restrict operating methods, which could adversely affect our production levels.

The Company uses a technique known as hydraulic fracturing whereby water, sand and other chemicals are injected into deep oil and gas bearing reservoirs. This process creates fractures in the rock formation within the reservoir which enables oil and natural gas to migrate to the wellbore. The Company primarily uses this technique in the Eagle Ford Shale in South Texas and in Western Canada. This practice is generally regulated by the states, but at times the U.S. has proposed regulation under the Safe Drinking Water Act. In June 2011, the State of Texas adopted a law requiring public disclosure of certain information regarding the components used in the hydraulic fracturing process. The Provinces of British Columbia and Alberta have also issued regulations related to hydraulic fracturing activities under their jurisdictions. It is possible that the states, the U.S., Canadian provinces or certain municipalities may adopt further laws or regulations which could render the process less effective or drive up its costs. If any such action is taken in the future, our production levels could be adversely affected or our costs of drilling and completion could be increased.

Capital financing may not always be available to fund Murphy s activities.

Murphy usually must spend and risk a significant amount of capital to find and develop reserves before revenue is generated from production. Although most capital needs are funded from operating cash flow, the timing of cash flows from operations and capital funding needs may not always coincide, and the levels of cash flow generated by operations may not fully cover capital funding requirements. Therefore, the Company maintains financing arrangements with lending institutions to meet certain funding needs. The Company must periodically renew these financing arrangements based on foreseeable financing needs or as they expire. The Company s primary bank financing facility was renewed in 2011. In 2013, the Company increased the capacity of its financing facility from $1.5 billion to $2.0 billion and extended the facility by one year such that it now expires in June 2017. Although not considered likely, there is the possibility that financing arrangements may not always be available at sufficient levels required to fund the Company s activities in future periods. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2015. Although not considered likely, the Company may not be able in the future to sell notes at reasonable rates in the marketplace.

Murphy has limited or virtually no control over several factors that could adversely affect the Company.

The ability of the Company to successfully manage development and operating costs is important because virtually all of the products it sells are energy commodities such as crude oil, natural gas and refined products, for which the Company has little or no influence on the sales prices or regional and worldwide consumer demand for these products. Economic slowdowns, such as those experienced in 2008 and 2009, had a detrimental effect on the worldwide demand for these energy commodities, which effectively led to reduced prices for oil, natural gas and refined products for a period of time. Lower prices for crude oil and natural gas inevitably lead to lower earnings for the Company. The Company also often experiences pressure on its operating and capital expenditures in periods of strong crude oil and natural gas prices because an increase in exploration and production activities due to high oil and gas sales prices generally leads to higher demand for, and consequently higher costs for, goods and services in the oil and gas industry.

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Many of the Company s major oil and natural gas producing properties are operated by others. Therefore, Murphy does not fully control all activities at certain of its significant revenue generating properties. During 2013, approximately 16% of the Company s total production was at fields operated by others, while at December 31, 2013, approximately 27% of the Company s total proved reserves were at fields operated by others.

Murphy s operations and earnings have been and will continue to be affected by worldwide political developments.

Many governments, including those that are members of the Organization of Petroleum Exporting Countries (OPEC), unilaterally intervene at times in the orderly market of crude oil and natural gas produced in their countries through such actions as setting prices, determining rates of production, and controlling who may buy and sell the production. As of December 31, 2013, approximately 28% of proved reserves, as defined by the U.S. Securities and Exchange Commission, were located in countries other than the U.S. and Canada. Certain of the reserves held outside these two countries could be considered to have more political risk. In addition, prices and availability of crude oil, natural gas and refined products could be influenced by political unrest and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy s operations and earnings include expropriation, tax changes, royalty increases, redefinition of international boundaries, preferential and discriminatory awarding of oil and gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Governments could also initiate regulations concerning matters such as currency fluctuations, protection and remediation of the environment, and concerns over the possibility of global warming being affected by human activity including the production and use of hydrocarbon energy. Additionally, because of the numerous countries in which the Company operates, certain other risks exist, including the application of the U.S. Foreign Corrupt Practices Act, the Canada Corruption of Foreign Officials Act, the Malaysia Anti-Corruption Commission Act, the U.K. Bribery Act, and similar anti-corruption compliance statutes. Because these and other factors too numerous to list are subject to changes caused by governmental and political considerations and are often made in response to changing internal and worldwide economic conditions and to actions of other governments or specific events, it is not practical to attempt to predict the effects of such factors on Murphy s future operations and earnings.

Murphy s business is subject to operational hazards and risks normally associated with the exploration for and production of oil and natural gas and the refining and marketing of crude oil and petroleum products.

The Company operates in urban and remote, and often inhospitable, areas around the world. The occurrence of an event, including but not limited to acts of nature such as hurricanes, floods, earthquakes and other forms of severe weather, and mechanical equipment failures, industrial accidents, fires, explosions, acts of war, civil unrest, piracy and acts of terrorism could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, and personal injury, including death, for which the Company could be deemed to be liable, and which could subject the Company to substantial fines and/or claims for punitive damages.

In April 2010, a drilling accident and subsequent oil spill occurred in the Gulf of Mexico at the Macondo well owned by other companies. Impacts of the accident and oil spill include additional regulations covering offshore drilling operations, a general lengthening in the time required for regulatory permitting, and higher costs for future drilling operations and offshore insurance. Additional regulations, possible further permitting delays and other restrictions associated with drilling and similar operations in the Gulf of Mexico could have an adverse affect on the Company s future costs of oil and natural gas produced in this area.

The location of many of Murphy s key assets causes the Company to be vulnerable to severe weather, including hurricanes and tropical storms. A number of significant oil and natural gas fields lie in offshore waters around the world. Probably the most vulnerable of the Company s offshore fields are in the U.S. Gulf of Mexico, where severe hurricanes and tropical storms have often led to shutdowns and damages. The U.S. hurricane season runs from June through November. Although the Company maintains insurance for such risks as described elsewhere in this Form 10-K report, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured.

Murphy may be unable to complete its announced reorganization plan.

The Company has announced the intended sale of its U.K. downstream business. Factors that could cause this event not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a deterioration in the business or prospects of Murphy or its subsidiaries, adverse developments in Murphy or its subsidiaries markets, adverse developments in the U.S. or global capital markets, credit markets or economies generally or a failure to execute a sale of the U.K. downstream operations on acceptable terms.

With the separation of its U.S. downstream operations, and the intended sale of its U.K. downstream business, Murphy will have fewer cash flow generating assets to service its debt.

With the separation of the Company s U.S. downstream assets, Murphy no longer has the cash flow generated from these assets to make interest and principal payments on its debt. Similarly, if the proposed sale of Murphy s U.K. downstream operations is completed, the Company will no longer have ongoing cash flows generated from these assets to service its debt. If Murphy s remaining exploration and production business is not successful as a stand-alone company, the Company may not have sufficient cash flow needed to make interest payments on outstanding notes, repay the notes at maturity or refinance the notes on acceptable terms, if at all.

Murphy s insurance may not be adequate to offset costs associated with certain events and there can be no assurance that insurance coverage will continue to be available in the future on terms that justify its purchase.

Murphy maintains insurance against certain, but not all, hazards that could arise from its operations. The Company maintains liability insurance sufficient to cover its share of gross insured claim costs up to approximately $700 million per occurrence and in the annual aggregate. These policies have up to $10 million in deductibles. Generally, this insurance covers various types of third party claims related to personal injury, death and property damage, including claims arising from sudden and accidental pollution events. The Company also maintains insurance coverage with an additional limit of $300 million per occurrence ($750 million for Gulf of Mexico operations not related to a named windstorm), all or part of which could be applicable to certain sudden and accidental pollution events. The occurrence of an event that is not insured or not fully insured could have a material adverse effect on the Company s financial condition and results of operations in the future.

Lawsuits against Murphy and its subsidiaries could adversely affect its operating results.

The Company is involved in numerous lawsuits seeking cash settlements for alleged personal injuries, property damages and other business-related matters. Certain of these lawsuits will take many years to resolve through court proceedings or negotiated settlements. None of these lawsuits are considered individually material or aggregate to a material amount in the opinion of management.

The Company is exposed to credit risks associated with sales of certain of its products to third parties.

Although Murphy limits its credit risk by selling its products to numerous entities worldwide, it still, at times, carries substantial credit risk from its customers. For certain oil and gas properties operated by the Company, other companies which own partial interests may not be able to meet their financial obligation to pay for their share of capital and operating costs as they come due. The inability of a purchaser of the Company s oil or natural gas or a partner of the Company to meet their respective payment obligations to the Company could have an adverse effect on Murphy s future earnings and cash flows.

Murphy s operations could be adversely affected by changes in foreign currency conversion rates.

The Company s worldwide operational scope exposes it to risks associated with foreign currencies. Most of the Company s business is transacted in U.S. dollars, therefore, the Company and most of its subsidiaries are U.S. dollar functional entities for accounting purposes. However, the Canadian dollar is the functional currency for all

Canadian operations and the British pound is the functional currency for U.K. refining and marketing operations. In certain countries, such as Malaysia, the United Kingdom and Canada, significant levels of transactions occur in currencies other than the functional currency. In Malaysia, such transactions include tax payments, while in the U.K., virtually all crude oil feedstock purchases and certain bulk product sales are priced in U.S. dollars, and in Canada, certain crude oil sales are priced in U.S. dollars. This exposure to currencies other than the functional currency can lead to significant impacts on consolidated financial results. In Malaysia, known future tax payments based in local currency are often hedged with contracts that match tax payment amounts and dates to lock in the exchange rate between the U.S. dollar and Malaysian ringgit. Exposures associated with deferred income tax liability balances in Malaysia are not hedged. A strengthening of the Malaysian ringgit against the U.S. dollar would be expected to lead to currency losses in consolidated income; gains would be expected in income if the ringgit weakens versus the dollar. Foreign exchange exposures between the U.S. dollar and the British pound are not hedged due to the frequency and volatility of U.S. dollar transactions in the U.K. downstream business. The Company would generally expect to incur currency losses when the U.S. dollar strengthens against the British pound and would conversely expect currency gains when the U.S. dollar weakens against the pound. In Canada, currency risk is often managed by selling forward U.S. dollars to match the collection dates for crude oil sold in that currency. See Note K in the consolidated financial statements for additional information on derivative contracts.

The costs and funding requirements related to the Company s retirement plans are affected by several factors.

A number of actuarial assumptions impact funding requirements for the Company s retirement plans. The most significant of these assumptions include return on assets, long-term interest rates and mortality. If the actual results for the plans vary significantly from the actuarial assumptions used, or if laws regulating such retirement plans are changed, Murphy could be required to make more significant funding payments to one or more of its retirement plans in the future and/or it could be required to record a larger liability for future obligations in its Consolidated Balance Sheet.

Item 1B. UNRESOLVED STAFF COMMENTS

The Company had no unresolved comments from the staff of the U.S. Securities and Exchange Commission as of December 31, 2013.

Item 2. PROPERTIES

Descriptions of the Company s oil and natural gas properties and refining and marketing operations are included in Item 1 of this Form 10-K report beginning on page 1. Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the Supplemental Oil and Gas Information section of this Annual Report on Form 10-K on pages F-50 to F-60 and in Note D Property, Plant and Equipment beginning on page F-18.

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Executive Officers of the Registrant

Present corporate office, length of service in office and age at February 1, 2014 of each of the Company s executive officers are reported in the following listing. Executive officers are elected annually but may be removed from office at any time by the Board of Directors.

Roger W. Jenkins Age 52; Chief Executive Officer since August 2013. Mr. Jenkins served as Chief Operating Officer from June 2012 to August 2013. Mr. Jenkins was Executive Vice President Exploration and Production from August 2009 through August 2013 and has served as President of the Company s exploration and production subsidiary since January 2009. He was Senior Vice President, North America for this subsidiary from September 2007 to December 2008.

Kevin G. Fitzgerald Age 58; Executive Vice President and Chief Financial Officer since December 2011. Mr. Fitzgerald was Senior Vice President and CFO from January 2007 to November 2011. He served as Treasurer from July 2001 through December 2006.

Walter K. Compton Age 51; Executive Vice President and General Counsel since February 2014. Mr. Compton was Senior Vice President and General Counsel from March 2011 to February 2014. He was Vice President, Law from February 2009 to February 2011 and was Manager, Law from November 1996 to January 2009.

Thomas McKinlay Age 50; Executive Vice President, U.K. Downstream since January 2013. Mr. McKinlay was Executive Vice President, Worldwide Downstream from January 2011 to January 2013 and Vice President, U.S. Manufacturing from August 2009 to January 2011. Mr. McKinlay was President of the Company s U.S. refining and marketing subsidiary from January 2011 to January 2013, and was Vice President, Supply and Transportation of this subsidiary from April 2009 to January 2011. From August 2008 to March 2009, Mr. McKinlay was General Manager, Supply and Transportation of this U.S. subsidiary, and from January 2007 to August 2008 was Supply Director for the Company s U.K. refining and marketing subsidiary.

Bill H. Stobaugh Age 62; Executive Vice President since February 2012. Mr. Stobaugh was Senior Vice President from February 2005 to January 2012.

John W. Eckart Age 55; Senior Vice President and Controller since December 2011. Mr. Eckart was Vice President and Controller from January 2007 to November 2011, and has served as Controller since March 2000.

Kelli M. Hammock Age 42; Senior Vice President, Administration since February 2014. Ms. Hammock was Vice President, Administration from December 2009 to February 2014 and was General Manager, Administration from June 2006 to November 2009.

Tim F. Butler Age 51; Vice President, Tax since August 2013. Mr. Butler was General Manager, Worldwide Taxation from August 2007 to August 2013.

John W. Dumas Age 59; Vice President, Corporate Insurance since February 2014. Mr. Dumas was Director, Corporate Insurance for the Company from 2005 to 2014.

Barry F.R. Jeffery Age 55; Vice President, Investor Relations since August 2013. Mr. Jeffery was Director, Investor Relations from September 2010 to August 2013. Mr. Jeffery served as General Manager, Business Development for the Company s former U.S. downstream subsidiary from November 2009 to August 2010 and was Manager, Crude Supply for this subsidiary from February 2007 to November 2009.

Allan J. Misner Age 47; Vice President, Internal Audit since February 2014. Mr. Misner served as Director, Internal Audit from 2007 to 2014.

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K. Todd Montgomery   Age 49; Vice President, Corporate Planning & Services since February 2014. Mr. Montgomery joined the Company in 2014 following 25 years of experience with another major independent oil company. With his prior employer, Mr. Montgomery s duties included responsibilities covering global production, reservoir engineering, strategic planning and development.

E. Ted Botner   Age 48; Secretary since August 2013. Mr. Botner has served as Manager, Law since August 2013. He was Senior Attorney from February 2010 to August 2013 and was General Manager, Malaysia for the Company s exploration and production subsidiary from July 2007 to January 2010.

John B. Gardner   Age 45; Treasurer since August 2013. Mr. Gardner was Assistant Treasurer from January 2012 to August 2013. He was Director of Planning and Special Projects for the Company s U.K. downstream subsidiary from March 2010 to December 2011, and was Controller USA for the Company s U.S. exploration and production subsidiary from January 2008 to February 2010.

Item 3. LEGAL PROCEEDINGS

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business. Based on information currently available to the Company, the ultimate resolution of matters referred to in this item is not expected to have a material adverse effect on the Company s net income, financial condition or liquidity in a future period.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

Item 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company s Common Stock is traded on the New York Stock Exchange using MUR as the trading symbol. There were 2,598 stockholders of record as of December 31, 2013. Information as to high and low market prices per share and dividends per share by quarter for 2013 and 2012 are reported on page F-61 of this Form 10-K report.

Murphy Oil Corporation

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[1,2]
October 1, 2013 to October 31, 2013		$		$ 500,000,000
November 1, 2013 to November 30, 2013	3,678,591	67.96[3]	3,678,591	250,000,000
December 1, 2013 to December 31, 2013				250,000,000
Total October 1, 2013 to December 31, 2013	**3,678,591**	**67.96**	**3,678,591**	**250,000,000**

[1] On October 16, 2012, the Company announced that its Board of Directors had authorized a buyback of up to $1.0 billion of the Company s Common stock. The buyback program has been extended to April 2014 by the Company s Board. On November 11, 2013, the Company announced that it had entered into a variable term, capped accelerated share repurchase transaction (ASR) with a major financial institution to repurchase an aggregate of $250 million of the Company s Common stock. The total aggregate number of shares repurchased pursuant to this ASR was determined by reference to the Rule 10b-18 volume-weighted price of the Company s Common stock, less a fixed discount, over the term of the ASR, subject to a minimum number of shares. The ASR was completed in January 2014, and the Company received an additional 284,743 shares upon completion of the ASR program.

[2] Through December 31, 2013, the Company has expended $750.0 million of the $1.0 billion approved program. With these purchases, the Company has acquired 12,007,712 shares under the approved stock buyback program, including additional shares received in January 2014 upon completion of the ASR that was open at December 31, 2013.

[3] The average price disclosed represents the maximum price per share for the Company s Common stock to be acquired under the ASR. The additional shares received upon completion of the ASR in January 2014 reduced the average price paid for the shares acquired to $63.08 per share. See Note U of the Company s consolidated financial statements regarding discussion of other 2014 share repurchase activities.

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SHAREHOLDER RETURN PERFORMANCE PRESENTATION

The following graph presents a comparison of cumulative five-year shareholder returns (including the reinvestment of dividends) as if a $100 investment was made on December 31, 2008 for the Company, the Standard & Poor s 500 Stock Index (S&P 500 Index) and the NYSE ARCA Oil Index. This performance information is furnished by the Company and is not considered as filed with this Form 10-K and it is not incorporated into any document that incorporates this Form 10-K by reference.

	2008	2009	2010	2011	2012	2013
Murphy Oil Corporation	100	124	174	133	152	195
S&P 500 Index	100	126	146	149	172	223
NYSE ARCA Oil Index	100	113	132	138	143	175

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Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	**2013**	2012	2011	2010	2009
Results of Operations for the Year					
Sales and other operating revenues	**$ 5,312,686**	4,608,563	4,222,520	3,556,461	2,982,769
Net cash provided by continuing operations	**3,210,695**	2,911,380	1,688,884	2,491,017	1,583,687
Income from continuing operations	**888,137**	806,494	539,198	618,493	656,187
Net income	**1,123,473**	970,876	872,702	798,081	837,621
Per Common share diluted					
Income from continuing operations	**$ 4.69**	4.14	2.77	3.20	3.41
Net income	**5.94**	4.99	4.49	4.13	4.35
Cash dividends per Common share	**1.25**	3.675[1]	1.10	1.05	1.00
Percentage return on[2]					
Average stockholders equity	**12.5**	10.5	9.9	10.3	12.5
Average borrowed and invested capital	**10.3**	9.6	9.2	9.4	10.9
Average total assets	**6.3**	6.2	5.7	5.9	7.0
Capital Expenditures for the Year[3]					
Continuing operations					
Exploration and production	**$ 3,943,956[4]**	4,185,028	2,748,008	2,023,309	1,790,163
Corporate and other	**22,014**	8,077	5,218	5,899	22,967
	3,965,970	4,193,105	2,753,226	2,029,208	1,813,130
Discontinued operations	**154,622**	190,881	190,586	418,932	394,139
	$ 4,120,592	4,383,986	2,943,812	2,448,140	2,207,269
Financial Condition at December 31					
Current ratio	**1.09**	1.21	1.22	1.21	1.55
Working capital	**$ 284,612**	699,502	622,743	619,783	1,194,087
Net property, plant and equipment	**13,481,055**	13,011,606	10,475,149	10,367,847	9,065,088
Total assets	**17,509,484**	17,522,643	14,138,138	14,233,243	12,756,359
Long-term debt	**2,936,563**	2,245,201	249,553	939,350	1,353,183
Stockholders equity	**8,595,730**	8,942,035	8,778,397	8,199,550	7,346,026
Per share	**46.87**	46.91	45.31	42.52	38.44
Long-term debt percent of capital employed[2]	**25.5**	20.1	2.8	10.3	15.6

1 Includes special dividend of $2.50 per share paid on December 3, 2012.

2 Company management uses certain measures for assessing its business results, including percentage return on average stockholders equity, percentage return on average borrowed and invested capital, and percentage return on average total assets. Additionally, the Company measures its long-term debt leverage using long-term debt as a percentage of total capital employed (long-term debt plus stockholders equity). We consistently disclose these financial measures because we believe our shareholders and other interested parties find such measures helpful in understanding trends and results of the Company and as a comparison of Murphy Oil to other companies in the oil and gas and other industries.

Specifically, these measures were computed as follows for each year:

Percentage return on average stockholders equity net income for the year (as per the consolidated statement of income) divided by a 12-month average for January to December of total stockholders equity.

Percentage return on average borrowed and invested capital the sum of net income for the year (as per the consolidated statement of income) plus after-tax interest expense for the year divided by a 12-month average for January to December of the sum of total long-term debt plus total stockholders equity.

Percentage return on average total assets net income for the year (as per the consolidated statement of income) divided by a 12-month average for January to December of total consolidated assets.

Long-term debt percent of capital employed total long-term debt at the balance sheet date (as per the consolidated balance sheet) divided by the sum of total long-term debt plus total stockholders equity at that date (as per the consolidated balance sheet).

These financial measures may be calculated differently than similarly titled measures that may be presented by other companies.

[3] Capital expenditures include accruals for incurred but unpaid capital activities, while property additions and dry holes in the Statements of Cash Flows are cash-based capital expenditures and do not include capital accruals and geological, geophysical and certain other exploration expenses that are not eligible for capitalization under oil and gas accounting rules.

[4] Excludes property addition of $358.0 million associated with non-cash capital lease at the Kakap field.

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Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND

RESULTS OF OPERATIONS

Overview

Murphy Oil Corporation is a worldwide oil and gas exploration and production company. Murphy owns refining and marketing operations in the United Kingdom, but has announced its intention to sell these U.K. assets. A more detailed description of the Company s significant assets can be found in Item 1 of this Form 10-K report.

Significant Company operating and financial highlights during 2013 were as follows:

- Completed the separation of Murphy USA Inc. on August 30, 2013 creating a significant value enhancement for shareholders.
- Continued to progress the sale of U.K. refining and marketing operations, with an expected completion date during 2014.
- Generated the second highest net income in the Company s history.
- Produced a Company record of more than 205,700 barrels of oil equivalent per day.
- Ended 2013 with a Company record level of proved reserves, and had organic replacement of proved reserves equal to 243% of production on a barrel of oil equivalent basis during the year.
- Repurchased almost eight million Common shares at a cost of $500 million.
- Made three natural gas discoveries in Block CA-2 in Brunei.

The year of 2013 was a period of significant transition for Murphy Oil Corporation. The Company had previously announced its intention to fully divest its refining and marketing businesses to become an independent oil and gas exploration and production company. Steps taken in 2013 led to significant progress with meeting this desire to focus only on upstream operations.

On August 30, 2013, the Company completed the separation of its former U.S. retail marketing business by distributing all common shares of this business to Murphy Oil s shareholders. This separation, commonly known as a spin-off , distributed one share of the retail marketing company, now known as Murphy USA Inc., for every four shares of Murphy Oil Corporation common stock owned on the record date of August 21, 2013. Murphy USA Inc. shares trade on the New York Stock Exchange under the ticker symbol MUSA . Additionally, the Company progressed the sale of its U.K. refining and marketing operations. Achievement of the U.K. sale, expected to occur during 2014, will complete the Company s transition to an independent oil and gas company. Both the U.S. and U.K. downstream businesses are now reported as discontinued operations within the Company s consolidated financial statements. Additionally, the Company includes U.K. oil and gas operations, which were sold in a series of transactions in the first half of 2013, as discontinued operations.

Murphy generates revenue by selling oil and natural gas production to customers in the United States, Canada and Malaysia. The Company s revenue is highly affected by the prices of oil and natural gas. In order to make a profit and generate cash in its exploration and production business, revenue generated from the sales of oil and natural gas produced must exceed the combined costs of producing these products, depreciation of capital expenditures, and expenses related to exploration, administration, and for capital borrowed from lending institutions and note holders.

Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company, especially the price of crude oil as oil represented approximately 66% of total hydrocarbons produced on an energy equivalent basis (one barrel of crude oil equals six thousand cubic feet of natural gas) by the Company s upstream operations in 2013. In 2014, the Company s ratio of hydrocarbon production represented by oil is expected to increase to more than 70% due to a combination of growing oil production and declining North American natural gas production. When oil-price linked natural gas is combined with oil production, the

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Company s 2014 total expected production is more than 80% linked to the price of oil. If the prices for crude oil and natural gas should weaken in 2014 or beyond, the Company would expect this to have an unfavorable impact on operating profits for its exploration and production business. As described on page 54, the Company has entered into derivative and forward delivery contracts that will reduce its exposure to changes in certain oil and natural gas prices in 2014 and 2015.

Worldwide oil prices in 2013 were generally comparable to 2012, while the sale prices for natural gas produced in North America was improved compared to the prior year. Among the various indices on which sales prices of the Company s crude oil are marketed, prices were mixed in 2013 versus the prior year. The sales price for a barrel of West Texas Intermediate (WTI) crude oil averaged $98.05 in 2013, $94.15 in 2012 and $95.11 in 2011. The sales price for a barrel of Platts Dated Brent declined to $108.66 per barrel in 2013, following averages of $111.67 per barrel and $111.26 per barrel in 2012 and 2011, respectively. The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $3.73 in 2013, $2.83 in 2012 and $4.03 in 2011. While the WTI index saw a 4% increase in 2013, Dated Brent fell back by 3% compared to 2012. During 2013 the discount for WTI crude compared to Dated Brent narrowed a bit compared to the two prior years. The WTI to Dated Brent discount was $10.61 per barrel during 2013, compared to $17.52 per barrel in 2012 and $16.15 per barrel in 2011. During 2012 the price of WTI fell slightly compared to 2011, however, certain other benchmark oil prices, including Dated Brent, experienced small increases in 2012 versus the prior year. NYMEX natural gas prices increased 32% in 2013 compared to 2012 generally due to more extreme weather conditions in North America in the later year which created more demand by gas consumers. Natural gas prices fell in 2012 from 2011 levels primarily due to expansion of North American gas supply and a warmer than normal winter season in 2012 in the U.S. and Canada. On an energy equivalent basis, the market continued to discount North American natural gas compared to crude oil in 2013. However, compared to 2012, this natural gas to oil price discount narrowed a bit during 2013. U.S. crude oil prices in early 2014 have been similar to 2013 average prices, while natural gas prices in North America in 2014 have thus far been above the 2013 levels due to cold temperatures across much of the Northern U.S. during the early winter season.

Results of Operations

Murphy Oil s results of operations, with associated diluted earnings per share (EPS), for the last three years are presented in the following table.

	Years Ended December 31		
(Millions of dollars, except EPS)	**2013**	2012	2011
Net income	**$ 1,123.5**	970.9	872.7
Diluted EPS	**5.94**	4.99	4.49
Income from continuing operations	**$ 888.1**	806.5	539.2
Diluted EPS	**4.69**	4.14	2.77
Income from discontinued operations	**$ 235.4**	164.4	333.5
Diluted EPS	**1.25**	0.85	1.72

Murphy Oil s net income in 2013 was 16% higher than 2012, with the improvement attributable to better earnings for exploration and production (E&P or upstream) operations and higher income from discontinued operations. Continuing operations income improved 10% primarily due to growth in oil production in the E&P business, but the Company experienced higher costs for Corporate activities that were not allocated to operating segments during 2013. The improvement in discontinued operations results by 43% was attributable to a gain on sale of U.K. oil and gas assets in 2013 and better profits for U.S. retail marketing operations, but U.K. downstream results was significantly below 2012 levels.

Net income in 2012 increased 11% compared to 2011 primarily due to higher earnings for continuing E&P operations, partially offset by both lower earnings for discontinued operations and higher net costs of corporate activities not allocated to operating segments.

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Further explanations of each of these variances are found in more detail in the following sections.

2013 vs. 2012 Net income in 2013 totaled $1,123.5 million ($5.94 per diluted share) compared to net income in 2012 of $970.9 million ($4.99 per diluted share). Income from continuing operations increased from $806.5 million ($4.14 per diluted share) in 2012 to $888.1 million ($4.69 per diluted share) in 2013. The 2013 improvement in income from continuing operations was attributable to higher oil sales volumes, lower impairment expense and higher tax benefits associated with investments in foreign upstream operations which are being exited. These were partially offset by higher extraction and exploration expenses, lower average oil sales prices, and higher costs associated with borrowed funds and company administration. Income from discontinued operations was $235.4 million ($1.25 per diluted share) in 2013, up from $164.4 million ($0.85 per diluted share) in 2012. Income from discontinued operations in both years included results for refining and marketing (R&M or downstream) operations in the U.S. and U.K. and for oil and gas production operations in the U.K. The improvement in discontinued operations in 2013 was attributable to a gain on disposal of all U.K. oil and gas assets during the year, coupled with stronger income contributions from the separated U.S. retail marketing business in 2013. These favorable factors were partially offset by unfavorable results for U.K. R&M operations caused by both significantly weaker operating margins and a $73.0 million charge to writedown the carrying value of these operating assets.

Sales and other operating revenues grew $704.1 million in 2013 compared to the prior year. Sales rose in 2013 primarily due to higher oil sales volumes associated with a 20% increase in oil production volumes. Sales also benefited from higher realized North American natural gas sales prices, which increased $0.61 per thousand cubic feet (MCF) in 2013 compared to the prior year. However, prices for worldwide average realized oil sales and Sarawak, Malaysia natural gas sales fell $1.98 per barrel and $0.84 per MCF, respectively, which had a detrimental effect on sales revenue. Additionally, natural gas sales volumes fell during 2013 due to both well decline in Western Canada caused by voluntary curtailment of drilling operations and lower net gas sales volumes offshore Malaysia caused by lower third party demand and a lower revenue share allocable to the Company for Sarawak gas sold compared to the prior year. Interest and other income was $66.5 million higher in 2013 than in 2012 primarily due to more favorable impacts from transactions denominated in foreign currencies during the most current year. Operating expenses increased $225.4 million in 2013 due to higher overall hydrocarbon production levels and costs related to shutdown of the Azurite field in Republic of the Congo. Exploration expenses in 2013 were $121.3 million more than 2012 due to higher unsuccessful exploratory drilling costs, primarily in the U.S. Gulf of Mexico, Western Canada, Australia and Cameroon, plus higher geophysical data acquisition costs, primarily in Vietnam, Australia, Indonesia, West Africa and the U.S. Lower undeveloped lease amortization in 2013 in the U.S., Canada and Kurdistan partially offset these higher drilling and geophysical costs. Selling and general expense rose $129.6 million in 2013 primarily due to higher compensation expense and costs related to separation of the U.S. retail marketing business. Depreciation, depletion and amortization expense increased $300.3 million in the current year due to both higher hydrocarbon sales volumes and higher per-unit depreciation rates mostly caused by increasing field development costs for new fields. Impairment of properties declined by $178.4 million in 2013 due to a $200.0 million charge at the Azurite field in the prior year compared to a $21.6 million writedown of certain Western Canada producing properties sold in 2013. Accretion of asset retirement obligations increased by $10.6 million in the current year due to both higher estimated upstream abandonment costs and a higher producing well count, which increased the level of future well abandonment liabilities recorded on a discounted basis. Interest expense rose $70.3 million in 2013 due to higher average borrowing levels in the current year, plus a higher average interest rate caused by a full year of interest applicable on notes payable issued near mid-year 2012. Interest capitalized to development operations in 2013 exceeded the prior year by $13.4 million primarily due to a higher level of oil development projects offshore Malaysia in the current year. Income tax expense increased $23.0 million in 2013 due to higher earnings before taxes partially offset by higher current year U.S. income tax benefits for tax deductions on investments in foreign upstream operations for which the Company is exiting. The consolidated effective tax rate was 39.7% in 2013 compared to 41.0% in 2012, with the lower rate in the later year primarily caused by higher U.S. tax benefits for investments in Republic of the Congo. The tax rate in both 2013 and 2012 were higher than the U.S. federal statutory tax rate of 35.0% due to both foreign tax rates in certain areas that exceeded the U.S.

federal tax rate and certain exploration and other expenses in foreign taxing jurisdictions for which no income tax benefit is currently being recognized because of the Company s uncertain ability to obtain tax benefits for these costs in 2013 or future years.

2012 vs. 2011 Net income in 2012 was $970.9 million ($4.99 per diluted share) compared to $872.7 million ($4.49 per diluted share) in 2011. Income from continuing operations was $806.5 million ($4.14 per diluted share) in 2012, up from $539.2 million ($2.77 per diluted share) in 2011. Earnings from continuing operations in 2012 increased primarily due to a combination of lower impairment charges, U.S. income tax benefits associated with investments in foreign upstream operations, higher crude oil sales volumes and lower exploration expenses. These were partially offset by lower North American natural gas sales prices and unfavorable effects of foreign exchange compared to the prior year. Net income in 2012 and 2011 included income from discontinued operations of $164.4 million ($0.85 per diluted share) and $333.5 million ($1.72 per diluted share), respectively. Income from discontinued operations in both years included results for downstream operations in the U.S. and U.K. and for oil and gas production operations in the U.K. In 2011 discontinued operations included these operations plus operating profits and a gain on disposal of two U.S. petroleum refineries sold in late 2011. Results for discontinued operations were $169.1 million less in 2012 primarily associated with no repeat of 2011 operating income and net gain on disposal for two U.S. refineries (Meraux, Louisiana and Superior, Wisconsin) and associated marketing assets which were sold in 2011. Additionally, weaker results for U.S. retail marketing operations in 2012 compared to 2011 were somewhat offset by improved results for U.K. refining and marketing operations during 2012.

Sales and other operating revenues grew $386.0 million in 2012 compared to 2011 primarily due to higher crude oil sales volumes for the E&P business. Gain (loss) on sale of assets was $23.1 million less in 2012 than 2011 because the earlier year included a $23.1 million gain on sale of natural gas storage assets in Spain. Interest and other operating income was lower by $22.0 million in 2012 compared to 2011 mostly due to an $18.4 million unfavorable pretax variance from the effects of transactions denominated in foreign currencies, plus interest income in 2011 of $2.7 million associated with a recovery of Federal royalties for certain deepwater Gulf of Mexico fields. Operating expenses were $104.6 million more in 2012 than 2011 due to higher oil and natural gas production costs caused mostly by higher production volumes in the later year. Exploration expenses were $108.4 million lower in 2012 compared to 2011 due to more drilling success in 2012, plus lower geophysical expense in the Gulf of Mexico, Malaysia, Brunei and the Kurdistan region of Iraq compared to 2011. Selling and general expenses were $40.7 million more in 2012 than in 2011 primarily due to higher employee compensation and professional services costs in the later year. Depreciation, depletion and amortization expense rose $288.4 million in 2012 versus 2011 due to higher crude oil and natural gas sales volumes in 2012 and higher E&P per-unit depreciation rates. Impairment of properties was $168.6 million lower in 2012 than in 2011 due to a smaller impairment charge in Republic of the Congo in 2012. Accretion of asset retirement obligations was $4.5 million more in 2012 than 2011 primarily due to higher discounted abandonment liabilities for wells drilled in 2012 in Malaysia, higher estimated abandonment costs for wells in the Gulf of Mexico, and higher future reclamation costs for synthetic oil operations at Syncrude. Redetermination of working interest at the Terra Nova field was a $5.4 million benefit in 2011 due to nonrecurring income achieved upon final settlement of the redetermination process in early 2011. Interest expense in 2012 was $1.7 million less than 2011 primarily due to lower average interest rates paid on borrowed funds in the later year, partially offset by the effects of higher average outstanding debt levels in 2012. The benefit from capitalized interest was $24.0 million higher in 2012 than the prior year due to larger levels of financing costs allocated to ongoing oil development projects in the later year. Income tax expense in 2012 was $67.2 million less than 2011 primarily due to U.S. income tax benefits of $108.3 million recognized in 2012 associated with investments in upstream operations in Republic of the Congo and Suriname. The consolidated effective tax rate was 41.0% in 2012 compared to 53.8% in 2011, with the lower rate in the later year caused by the U.S. tax benefits for Republic of the Congo and Suriname, a lower percentage of earnings in higher tax jurisdictions in 2012, and lower current year exploration and other expenses in foreign jurisdictions where no income tax benefit can presently be recognized due to no assurance that these expenses will be realized in 2012 or future years to reduce taxes owed. The tax rates in both 2012 and 2011 were higher than the U.S. federal statutory tax rate of 35.0% due to foreign tax rates that exceeded the U.S.

federal tax rate in certain areas, and certain exploration and other expenses in foreign taxing jurisdictions for which no income tax benefit is currently being recognized because of the Company s uncertain ability to obtain tax benefits for these costs in 2012 or future years.

Segment Results In the following table, the Company s results of operations for the three years ended December 31, 2013, are presented by segment. More detailed reviews of operating results for the Company s exploration and production and other activities follow the table.

(Millions of dollars)	**2013**	2012	2011
Exploration and production continuing operations			
United States	**$ 435.4**	168.0	152.7
Canada	**180.8**	208.1	328.0
Malaysia	**786.4**	894.2	812.7
Republic of the Congo	**(9.0)**	(241.1)	(385.3)
Other	**(364.8)**	(124.2)	(293.9)
Total exploration and production continuing operations	**1,028.8**	905.0	614.2
Corporate and other	**(140.7)**	(98.5)	(75.0)
Income from continuing operations	**888.1**	806.5	539.2
Income from discontinued operations	**235.4**	164.4	333.5
Net income	**$ 1,123.5**	970.9	872.7

Exploration and Production Earnings from exploration and production (E&P) continuing operations were $1,028.8 million in 2013, $905.0 million in 2012 and $614.2 million in 2011.

E&P income in 2013 was $123.8 million higher than in 2012 primarily due to higher crude oil sales volumes in 2013 and lower impairment charges in the current year. The 2013 period also had higher North American natural gas sales prices and higher U.S. income tax benefits for investments in foreign upstream operations where the Company is exiting. The 2013 E&P results included lower crude oil sales realizations and higher expenses for oil and gas extraction, exploration and administrative activities. Crude oil sales volumes for continuing operations in 2013 were 23% higher than 2012. The most significant increase occurred in the U.S. where ongoing development operations during the year led to larger oil production in the Eagle Ford Shale area of South Texas. Oil sales volumes also increased in the heavy oil area of Canada following an acquisition of properties in this area in late 2012. Sales volumes were higher offshore Eastern Canada due to increased production at the Terra Nova field, which had more downtime for maintenance in 2012. Sales volumes of synthetic crude oil were lower in 2013 due to more downtime for maintenance during the current year. The average realized sales price for crude oil, condensate and gas liquids declined 2% in 2013 to an average of $93.60 per barrel. Natural gas sales volumes for continuing operations decreased 13% in 2013 and the reduction was primarily attributable to lower gas volumes produced during the current year at the Tupper and Tupper West areas in Western Canada. The Company has voluntarily curtailed drilling activities in this area during the last few years due to low North American gas sales prices. Natural gas sales volumes were also lower during 2013 in Malaysia due to reduced customer demand and a lower entitlement percentage allocable to the Company from fields offshore Sarawak. E&P production expenses were $225.4 million higher in 2013 primarily due to more volumes produced in the Eagle Ford Shale and $82.5 million of costs associated with abandonment activities at the Azurite field, offshore Republic of the Congo. Depreciation, depletion and amortization increased $299.2 million due to both higher overall production and a higher per-unit depreciation rate on new production volumes. Exploration expense rose $121.3 million in 2013 due to higher costs for both unsuccessful exploratory drilling and geophysical data acquisitions, but these were partially offset by lower amortization expense for unproved oil and gas leases. The prior year included a $200.0 million impairment charge to reduce the carrying value of the Azurite oil field in Republic of the Congo. This field went off production in October 2013 and field abandonment operations were underway at year-end 2013. Income tax benefits associated with investments in foreign upstream operations where the Company is exiting were $25.2 million higher in 2013 than 2012. These larger tax benefits were primarily related to U.S. tax deductions associated with investments in Republic of the Congo.

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Income for E&P continuing operations in 2012 was $290.8 million more than in 2011. The increase was primarily attributable to lower impairment charges of $168.6 million in Republic of the Congo in 2012, favorable tax benefits of $108.3 million in 2012 for investments in upstream operations in Republic of the Congo and Suriname, plus higher crude oil and natural gas sales volumes and stronger crude oil sales prices in the later year. The Company s average realized sales price for crude oil, condensate and gas liquids in 2012 for continuing operations increased $1.40 per barrel over 2011. The Company s average natural gas sales prices in Sarawak, Malaysia were also higher in 2012 than 2011, but natural gas sales prices in 2012 in North America were significantly below 2011 levels. Crude oil and liquids sales volumes for continuing operations increased 11% in 2012 while natural gas sales volumes rose 7%. The increase in hydrocarbon sales volumes in 2012 led to higher expenses for production and depreciation of $104.5 million and $288.4 million, respectively. The 2012 year had less exploration expenses of $108.5 million compared to 2011, essentially due to lower expenses related to unsuccessful exploratory drilling and geophysical activities. Crude oil sales volumes increased in 2012 in the U.S. primarily due to higher volumes produced in the Eagle Ford Shale area of South Texas. Conventional oil sales volumes in Canada in 2012 were less than 2011 primarily due to lower gross production at the Terra Nova field, where more downtime for maintenance occurred in 2012. Synthetic oil sales volumes at Syncrude increased in 2012 due to higher gross production compared to 2011. Sales volumes for crude oil produced in Malaysia were higher in 2012 primarily due to new wells brought on production at the Kikeh field offshore Sabah. Crude oil sales volumes decreased in 2012 in Republic of the Congo due to field decline and a well failure at the Azurite field. Natural gas sales volumes in 2012 increased compared to the prior year principally due to more wells producing for a longer period in the Tupper area in Western Canada and higher gas volumes produced in the Eagle Ford Shale.

The results of operations for oil and gas producing activities for each of the last three years are shown by major operating areas on pages F-57 and F-58 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 5 of the 2013 Annual Report.

A summary of oil and gas revenues is presented in the following table.

(Millions of dollars)	**2013**	2012	2011
United States Oil and gas liquids	**$ 1,724.7**	976.1	648.8
Natural gas	**72.7**	54.2	71.1
Canada Conventional oil and gas liquids	**507.2**	411.7	505.6
Synthetic oil	**441.0**	463.1	506.6
Natural gas	**198.1**	209.8	280.2
Malaysia Oil and gas liquids	**1,875.0**	1,946.0	1,583.0
Natural gas	**404.0**	481.1	461.3
Republic of the Congo oil	**83.6**	57.6	148.8
Total oil and gas revenues	**$ 5,306.3**	4,599.6	4,205.4

The Company s total crude oil, condensate and natural gas liquids production averaged 135,078 barrels per day in 2013, compared to 112,591 barrels per day in 2012 and 103,160 barrels per day in 2011.

United States oil production increased from 26,090 barrels per day in 2012 to a U.S. Company record of 48,387 barrels per day in 2013 with the 85% volume increase virtually all related to drilling and other development operations in the Eagle Ford Shale area. The Company s Eagle Ford Shale drilling program in South Texas utilized an average of almost eight drilling rigs throughout 2013 and drilling will continue throughout 2014. Production of heavy oil in Western Canada was 9,128 barrels per day in 2013, up from 7,241 barrels per day in 2012, primarily due to volumes in the current year at properties acquired near the end of 2012. Oil production offshore Canada rose from 6,986 barrels per day in 2012 to 9,099 barrels per day in 2013 primarily due to less downtime in the current year at the Terra Nova field. Synthetic oil operations at Syncrude had net production of 12,886 barrels per day in 2013, down from 13,830 barrels per day in 2012, with the decrease caused by more

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facility downtime for maintenance in the current year. Oil production in Malaysia increased from 52,663 barrels per day in 2012 to 53,766 barrels per day in 2013, primarily due to start-up of four new oil fields offshore Sarawak in the second half of 2013. Additionally, oil volumes benefited from the early production system at the Kakap-Gumusut field being operational for all of 2013 following a late 2012 start-up. The full Kakap-Gumusut field production system is expected to come onstream in 2014. Oil production at the Kikeh field decreased in 2013 primarily due to well decline. Oil production in Republic of the Congo was lower in 2013 due to continued well decline that led to the field being shut down in October 2013. The Company sold all of its U.K. oil and gas properties through a series of transactions during the first half of the year, and U.K. oil production therefore declined in 2013. All U.K. oil and gas production volumes have been reported as discontinued operations.

United States crude oil production averaged 26,090 barrels per day in 2012, a 52% increase from 17,148 barrels per day in 2011. The U.S. increase was primarily attributable to development drilling in the Eagle Ford Shale area. Heavy oil production in Western Canada of 7,241 barrels per day in 2012 was about flat with 2011. Crude oil production offshore Canada fell from 9,204 barrels per day in 2011 to 6,986 barrels per day in 2012 essentially due to more downtime for maintenance at the Terra Nova field and well decline at the Hibernia field. Synthetic oil production of 13,830 barrels per day in 2012 slightly exceeded 2011 volumes of 13,498 per day. Crude oil and liquids production in Malaysia averaged 52,663 barrels per day in 2012, up from 48,551 barrels per day in 2011, with the increase mainly due to additional wells brought on production at the Kikeh field. Oil production in Republic of the Congo fell to 2,078 barrels per day in 2012 after averaging 4,989 barrels per day in 2011, with the reduction due to a well that went off production during 2012 and normal decline at other wells in the field. Crude oil production from discontinued U.K. operations was 3,458 barrels per day in 2012 compared to 2,423 barrels per day in 2011. The U.K. increase in 2012 was primarily at Schiehallion, where better overall performance more than offset lower volumes produced at the Mungo/Monan field.

Worldwide sales of natural gas were 423.8 million cubic feet (MMCF) per day in 2013, after averaging a Company record 490.1 MMCF per day in 2012 and 457.4 MMCF per day in 2011.

Natural gas sales volumes in the U.S. averaged 53.2 MMCF per day in 2013, slightly above the 53.0 MMCF per day in 2012 as higher production in the Eagle Ford Shale was essentially offset by declines in the Gulf of Mexico and other onshore operations. Natural gas volumes in Canada fell from 217.0 MMCF per day in 2012 to 175.4 MMCF per day in 2013 primarily due to well decline at the Tupper and Tupper West areas in Western Canada. The Company has voluntarily curtailed drilling activities in this dry gas basin due to historically low North American natural gas sales prices. Natural gas sales volume offshore Sarawak, Malaysia declined to 164.7 MMCF per day in 2013 compared to 174.3 MMCF per day in 2012. This reduction was caused by a combination of lower third party demand and a lower entitlement percentage allocable to the Company under the production sharing contract. Kikeh gas volumes offshore Sabah, Malaysia fell from 42.5 MMCF per day in 2012 to 29.7 MMCF per day in 2013 primarily due to more downtime for maintenance at the third party onshore receiving facility. Natural gas production from discontinued operations in the U.K. declined from 3.4 MMCF per day in 2012 to 0.8 MMCF per day in 2013 due to the Company selling these properties during the first half of 2013.

Natural gas sales volumes in the U.S. were 53.0 MMCF per day in 2012, up from 2011 production of 47.2 MMCF per day as higher gas volumes in the Eagle Ford Shale area more than offset declines at fields in the Gulf of Mexico. Natural gas volumes in Canada increased from 188.8 MMCF per day in 2011 to 217.0 MMCF per day in 2012 essentially due to higher gas volumes produced at the Tupper area, as more wells were on production at Tupper West during 2012. Natural gas sales volumes offshore Sarawak, Malaysia averaged 174.3 MMCF per day in 2012 following volumes of 176.9 MMCF per day in 2011. Gas sales at the Kikeh field averaged 42.5 MMCF per day in 2012, up from 40.5 MMCF per day during the prior year. Natural gas sales volumes in the U.K. reported as discontinued operations fell from 3.9 MMCF per day in 2011 to 3.4 MMCF per day in 2012 due to well decline at the Mungo/Monan field during the later year.

The Company s average worldwide realized sales price for crude oil, condensate and gas liquids from continuing operations was $93.60 per barrel in 2013 compared to $95.58 per barrel in 2012 and $94.18 per barrel in 2011.

The average realized oil sales price for continuing operations fell by 2% in 2013 compared to the prior year. Oil prices on various indices were mixed in 2013 compared to the prior year. Although West Texas Intermediate crude oil prices increased about 4% in 2013, most of the Company s oil is sold on other indices which actually declined in 2013 compared to 2012. Dated Brent prices and Kikeh benchmark prices declined in 2013 by about 3% and 2%, respectively. Compared to 2012, the Company s realized oil price in the U.S. declined by about 5% to $97.69 per barrel primarily due to a higher mix of natural gas liquids in the later year. This average 2013 oil price includes a mix of $101.70 per barrel for crude oil and $30.31 per barrel for natural gas liquids. Heavy oil price realizations in Canada increased 1% to $46.80 per barrel. Oil prices offshore Eastern Canada were $108.64 per barrel, down 3% from 2012. Oil produced at the Syncrude project averaged $96.09 per barrel in 2013, an increase of 5%. Malaysian crude oil was sold at an average of $94.27 per barrel in 2013, which was a decline of 3% from the prior year. Average crude oil sales prices in Republic of the Congo were $109.43 per barrel in 2013, a 2% increase from the prior year.

During 2012, the average realized oil sales price for continuing operations increased 1% compared to 2011. The 2012 higher realized price was favorable to the 1% reduction in West Texas Intermediate (WTI) sales price between the years. Other benchmark oil prices used for sale of Company crude oil, such as Dated Brent, performed more favorably than WTI. During 2012, the Company began to sell its Kikeh crude oil based on a new Kikeh benchmark price. Kikeh oil had been sold since late 2010 on a Brent crude oil benchmark. Compared to 2011, the Company s average 2012 crude oil sales prices fell 1% in the U.S. to average $102.60 per barrel. Heavy oil sales prices in Canada fell 19% in 2012 to an average of $46.45 per barrel. Offshore Canada oil sold at $112.08 per barrel in 2012, an increase of 2%. Canadian synthetic crude oil sold for 11% less in 2012 and averaged $91.85 per barrel. The crude oil sales price in Malaysia increased 8% to an average price of $97.29 per barrel in 2012. Crude oil sold in Republic of the Congo increased 4% to a price of $107.26 per barrel in 2012.

During 2013, the Company s realized North American natural gas sales price averaged $3.26 per thousand cubic feet (MCF), a 23% increase compared to 2012. Natural gas produced in 2013 offshore Sarawak was sold at an average price of $6.66 per MCF, a decline of 11% from 2012, which was essentially caused by contractually required revenue sharing for a higher percentage of gas produced during the just completed year.

The Company s North American natural gas prices retracted in 2012 compared to 2011, while prices in other areas were a bit stronger in 2012. North American natural gas sales prices were hurt by an oversupply of gas caused by both a growing profile of unconventional gas production on the continent and an unusually warm winter season in the primary gas consuming markets in the U.S. during 2012. The Company s average sales prices for natural gas in North America decreased 35% to $2.65 per MCF in 2012, which was composed of a 33% decline to $2.76 per MCF in the U.S. and a 36% decline to $2.62 per MCF in Canada. Natural gas produced offshore Sarawak sold for 6% more in 2012 than in 2011 and averaged $7.50 per MCF in the later year.

Based on 2013 sales volumes and deducting taxes at statutory rates, each $1.00 per barrel and $0.10 per MCF fluctuation in prices would have affected 2013 earnings from exploration and production continuing operations by $32.2 million and $10.4 million, respectively. The effect of these price fluctuations on consolidated net income cannot be measured precisely because operating results of the Company s discontinued refining and marketing operations could have been affected differently.

Production expenses for continuing operations were $1,340.2 million in 2013, $1,114.8 million in 2012 and $1,010.3 million in 2011. These amounts are shown by major operating area on pages F-57 and F-58 of this Form 10-K report. Costs per equivalent barrel sold, excluding ad valorem and severance taxes as applicable, during the last three years are shown in the following table.

(Dollars per equivalent barrel)	**2013**	2012	2011
United States	**$ 13.10**	17.64	17.30
Canada			
Excluding synthetic oil	**10.50**	8.86	8.55
Synthetic oil	**47.47**	43.26	46.84
Malaysia	**12.15**	12.78	13.66
Worldwide excluding synthetic oil and Republic of the Congo	**12.03**	12.61	12.69

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Production expense per equivalent barrel in the U.S. declined in 2013 compared to 2012 due to both higher production volumes and cost management actions in the Eagle Ford Shale area. In 2013, costs per barrel in the Eagle Ford Shale were below the U.S. average rate. Continued cost management activities and anticipated higher production at the Eagle Ford Shale is expected to lead to lower U.S. production expense per barrel in 2014. The per-unit costs for Canadian conventional oil and gas operations, excluding synthetic oil, was higher in 2013 compared to 2012, which was caused by a higher mix of more expensive Seal area heavy oil coupled with a reduction in less expensive natural gas production in the Tupper and Tupper West areas. Lower maintenance costs anticipated in 2014 at the Terra Nova field should lead to a small reduction in per-unit costs in Canada in that year. Higher cost per barrel in 2013 compared to 2012 at Canadian synthetic oil operations was primarily caused by more overall maintenance costs and lower production volumes in the just completed year. No major variance in per-unit costs is anticipated at Syncrude in 2014. Production cost per unit in Malaysia was down in 2013 compared to 2012, with the reduction primarily associated with lower costs for the early production system at the Kakap-Gumusut field. A higher mix of oil-weighted production is anticipated to lead to an increase in per-unit costs in Malaysia in 2014. Production expense in Republic of the Congo in 2013 included $82.5 million related to abandonment and other exit activities at the Azurite field. These costs will not repeat in 2014 and due to field shutdown in late 2013, the effect of Azurite production has been omitted from the table on page 32.

Production expense per equivalent barrel in the U.S. increased in 2012 compared to 2011 due to a significantly larger proportion of production in the later year coming from the Eagle Ford Shale in South Texas, where the average per-barrel cost exceeded the U.S. average. Cost per barrel for Canada conventional oil and gas operations, excluding synthetic oil, was higher in 2012 than 2011 due to additional maintenance costs in the later year at the Terra Nova field. This Canadian cost increase was tempered by higher natural gas production at the lower cost Tupper area. The reduction in production costs per barrel for synthetic oil operations in 2012 compared to 2011 was attributable to lower natural gas power costs in the later year. Production expense in Malaysia declined in 2012 compared to 2011 due to less well maintenance and workover costs at the Kikeh field. Per-barrel production expense in 2012 in Republic of the Congo was significantly higher than 2011 due to lower production levels and unsuccessful workover costs at a well in the Azurite field.

Exploration expenses for continuing operations for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-57 and F-58 on this Form 10-K report. Expenses other than undeveloped lease amortization are included in the capital expenditures total for exploration and production activities.

(Millions of dollars)	**2013**	2012	2011
Dry holes	**$ 262.9**	181.9	251.0
Geological and geophysical	**117.5**	32.2	79.3
Other	**54.9**	37.0	40.9
	435.3	251.1	371.2
Undeveloped lease amortization	**66.9**	129.8	118.2
Total exploration expenses	**$ 502.2**	380.9	489.4

Dry hole expense in 2013 was $81.0 million more than 2012 due to higher unsuccessful exploratory drilling costs in the just completed year in the Gulf of Mexico, Western Canada, Australia and Cameroon. Lower dry hole costs in 2013 in Malaysia, Republic of the Congo and Kurdistan somewhat offset the higher costs in other areas. Geological and geophysical (G&G) expenses were $85.3 million higher in 2013 compared to 2012. The increase in G&G expenses in 2013 was mostly attributable to higher spending on seismic in Vietnam, Indonesia, Australia, West Africa and the Gulf of Mexico, but 2013 included lower seismic spending offshore Malaysia. Other exploration costs were $17.9 million more in 2013 than 2012 mostly due to higher office costs for exploration activities primarily in West Africa, the Kurdistan region of Iraq, Vietnam and Australia. Undeveloped lease amortization expense was $62.9 million lower in 2013 than 2012 principally due to less unproved lease amortization costs associated with concessions in the Kurdistan region of Iraq, the Eagle Ford Shale area and Western Canada.

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Dry hole expense was $69.1 million lower in 2012 than in 2011 due to better drilling success coupled with lower exploratory drilling spending. Dry hole expense in 2012 in other foreign areas was significantly lower than in 2011 primarily due to unsuccessful wells drilled in the earlier year in Brunei, Indonesia and Suriname. Dry hole expense in Canada was also significantly lower in 2012 due to fewer unsuccessful wells drilled in Southern Alberta in 2012. Dry hole expense in the U.S. was higher in 2012 mostly due to a decision by the owners in 2012 not to develop a well drilled in a prior year in the deepwater Gulf of Mexico; the well was expensed in 2012. Malaysian operations had higher dry hole expense in 2012 due to an unsuccessful well drilled in Block P and expensing of two wells drilled in a prior year offshore Sarawak caused by a decision to forego development plans for these wells. Dry hole expense in Republic of the Congo was higher in 2012 than 2011 due to expensing two wildcat wells following unsuccessful drilling in the MPN block in the later year. G&G expenses were $47.1 million lower in 2012 than 2011. Areas with lower spending on seismic in 2012 included the Gulf of Mexico, Brunei, the Kurdistan region of Iraq, and Block H Malaysia. Other exploration costs in 2012 were $3.9 million below 2011 levels primarily due to lower lease rentals on undeveloped acreage in Western Canada in 2012. Undeveloped leasehold amortization expense rose $11.6 million in 2012 compared to 2011, primarily due to higher amortization associated with Eagle Ford Shale area leases.

The Company s E&P operations had lower impairment expense of $178.4 million in 2013 when compared to the prior year. The 2013 expense was associated with a writedown of property value in the Kainai area of Western Canada based on a sale of the property at a price below the carrying value. In 2012, the Company recorded an impairment charge of $200.0 million for oil production operations at the Azurite field, offshore Republic of the Congo. The 2012 charge for Azurite was required due to the removal of all proved reserves at year-end 2012 following the Company s decision to cease redrilling operations on a well that went off production during that year. The reserves associated with the remaining producing wells were insufficient to allow for booking as proved reserves due to uneconomic results. A $368.6 million impairment charge was recorded in 2011 to reduce the carrying value of Azurite necessitated by a reduction in the field s proved oil reserves at year-end 2011 due to poor performance for certain wells.

Depreciation, depletion and amortization expense for continuing exploration and production operations totaled $1,543.6 million in 2013, $1,244.4 million in 2012 and $956.0 million in 2011. The $299.2 million increase in 2013 was attributable to a combination of higher total sales volumes on a barrel equivalent basis and a higher per-unit depreciation rate. Additional production volumes at the Eagle Ford Shale and new oil produced at fields offshore Sarawak had higher overall per-unit rates compared to the average rate for the Company. The $288.4 million increase in 2012 compared to 2011 was primarily caused by higher overall volumes of oil and natural gas sold during 2012. Additionally, the average per-unit depreciation rate increased in 2012, primarily due to a higher mix of production from the Eagle Ford Shale and a higher unit rate at Kikeh due to development drilling activities at the field.

The exploration and production business recorded expenses of $49.0 million in 2013, $38.4 million in 2012 and $33.8 million in 2011 for accretion on discounted abandonment liabilities. Because the liability for future abandonment of wells and other facilities is carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment. The $10.6 million increase in accretion expense in 2013 compared to the prior year was due to additional wells drilled in the Eagle Ford Shale area, as well as higher estimated abandonment liabilities for synthetic oil operations in Canada and oil fields in Malaysia and Congo. The $4.6 million increase in accretion expense in 2012 compared to 2011 was due to additional wells drilled during the later year in Malaysia and higher estimated abandonment costs for wells in the Gulf of Mexico and for synthetic oil operations at Syncrude.

The effective income tax rate for exploration and production continuing operations was 38.9% in 2013, 40.1% in 2012 and 52.6% in 2011. The 2013 overall effective tax rate for E&P operations was slightly lower than 2012 due to recognizing higher U.S. income tax benefits associated with investments in upstream operations in Republic of the Congo and Kurdistan, where the Company is exiting. These U.S. benefits amounted to $133.5 million in 2013. The effective income tax rate was significantly lower in 2012 than 2011 mostly due to

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U.S. income tax benefits of $108.3 million recorded in 2012 associated with investments in upstream operations in Republic of the Congo and Suriname. Additionally, 2012 had lower exploration expenses in foreign jurisdictions where no tax benefit is available at the present time due to lack of available revenue needed to realize a current or future benefit. Income tax expense in 2011 was reduced by a $25.6 million benefit for expenses incurred in prior years in Block P, Malaysia. It was determined during 2011 that Block P expenses are deductible against taxable income generated in Block K Malaysia. The effective tax rates in all three years exceeded the U.S. statutory tax rate of 35.0% due to higher overall foreign tax rates and exploration and other expenses in areas where current tax benefits cannot be recorded by the Company. Tax jurisdictions with no current tax benefit on expenses primarily include certain non-revenue generating areas in Malaysia as well as other foreign exploration areas in which the Company operates. Each main exploration area in Malaysia is currently considered a distinct taxable entity and expenses in certain areas may not be used to offset revenues generated in other areas. No tax benefits have thus far been recognized for costs incurred for Block H, offshore Sabah, and Blocks PM 311/312, offshore Peninsular Malaysia.

At December 31, 2013, 125.8 million barrels of the Company s U.S. proved oil reserves and 72.4 billion cubic feet of U.S. proved natural gas reserves were undeveloped. Approximately 93% of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company s Eagle Ford Shale operations in South Texas. Further drilling and facility construction are generally required to move the undeveloped reserves in the Eagle Ford Shale area to developed. In the Western Canadian Sedimentary Basin, total proved undeveloped natural gas reserves totaled 178.8 billion cubic feet, with the migration of these reserves, primarily in the Tupper and Tupper West areas, dependent on both development drilling and completion of processing and transportation facilities. In Block K Malaysia, oil reserves of 33.9 million barrels for the Kakap-Gumusut field are undeveloped pending completion of the main facilities and additional development drilling directed by another company. Additionally, the Kikeh field had undeveloped oil reserves of 7.7 million barrels, which are subject to further drilling before being moved to developed, and the Siakap North-Petai field had undeveloped oil reserves of 5.7 million barrels pending completion of development facilities. Also in Malaysia, there were 99.3 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2013, which were held under the undeveloped category pending completion of development drilling and facilities. The deepwaters of the Gulf of Mexico accounted for additional proved undeveloped reserves of 9.5 million equivalent barrels of oil at December 31, 2013. On a worldwide basis, the Company spent approximately $3.40 billion in 2013, $3.30 billion in 2012 and $1.88 billion in 2011 to develop proved reserves.

Refining and Marketing On August 30, 2013, the Company spun-off to shareholders its U.S. retail marketing business. The now separate, publicly traded U.S. retail company named Murphy USA Inc. is listed on the New York Stock Exchange under the symbol MUSA . Murphy Oil continues to actively market for sale its U.K. refining and marketing business. Both the U.S. and U.K. downstream businesses are reported as discontinued operations for all periods presented. Further discussion of the results of discontinued operations is included following the Corporate section.

Corporate The after-tax costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and unallocated corporate overhead were $140.7 million in 2013, $98.5 million in 2012 and $75.0 million in 2011.

The net cost of corporate activities in 2013 was $42.2 million more than in 2012, primarily due to higher net interest and administrative expenses. These were partially offset by more favorable effects of foreign currency exchange, which were associated with transactions denominated in currencies other than the respective operation s predominant functional currency. Interest income in 2013 was $2.5 million less than 2012, principally due to lower invested cash balances in Canada during the later year. Net interest expense, after capitalization of finance-related costs to development projects, was $57.0 million higher in 2013 than 2012. This unfavorable variance was principally due to higher average debt levels in the current year coupled with a higher average interest rate caused by a full year of long-term notes that were sold in 2012. These were partially offset by higher amounts of interest capitalized to development projects in Malaysia in 2013. Administrative expenses

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associated with corporate activities were $78.3 million higher in 2013 compared to 2012, primarily associated with higher overall employee compensation costs and professional service expenses related to separation of the U.S. downstream business. The effect of foreign currency exchange after taxes was a gain of $70.3 million in 2013 compared to a minimal impact in 2012. The most significant impact from foreign currencies occurred in Malaysia, where the U.S. dollar generally strengthened against the Malaysian ringgit in 2013 after having weakened against this currency during 2012. The stronger U.S. currency in 2013 reduced the dollar cost of tax liabilities in Malaysia which are payable in the local currency. The Malaysian operation s functional currency is the U.S. dollar. Foreign currency transaction effects in the U.K. were also favorable in 2013 compared to 2012. Income tax benefits associated with Corporate activities were $28.3 million higher in 2013, essentially in line with the larger pretax net costs in the current year.

The net cost of corporate activities rose $23.5 million in 2012 compared to 2011. The most significant variance between years related to the effects of foreign currency exchange. While 2011 benefited from after-tax gains of $20.7 million from foreign currency exchange, the foreign currency effects in 2012 were minimal. During 2012, the after-tax impact of foreign exchange losses for Malaysian operations was essentially offset by after-tax foreign exchange benefits in the U.K. Interest income was $3.6 million less in 2012 compared to the prior year, with the variance primarily related to interest earned in 2011 on a U.S. Federal royalty refund. Administrative expenses for corporate activities were up $18.8 million in 2012 compared to 2011 due to both higher employee compensation and higher professional services costs. The increase in professional services in 2012 was primarily associated with both preparing for separation of the U.S. R&M business and the intended sale of the U.K. R&M business. Net interest expense, after capitalization of finance-related costs to development projects, was $25.8 million lower in 2012 than 2011 mostly due to larger amounts of interest capitalized on oil development projects during 2012. Income taxes associated with corporate activities in 2012 were unfavorable to 2011 primarily due to pretax variances from foreign currency exchange effects.

Discontinued Operations The Company has presented a number of businesses as discontinued operations in its consolidated financial statements. These businesses principally include:

- U.S. retail marketing company spun-off to shareholders on August 30, 2013. Results of operations are included in the Company s financial statements through the date of spin-off.

- U.K. refining and marketing company held for sale at year-end 2013.

- U.K. oil and gas assets sold through a series of transactions in the first half of 2013. The Company s financial statements include the results of operations through the respective date of asset sale, plus the cumulative gain realized upon sale. Total cash proceeds from sale of these assets were $282.2 million.

- Two former refineries in the U.S. that were sold on September 30, 2011 and October 1, 2011. The Company s financial statements include the results of these operations through the date of sale, plus the net gain associated with the disposals. Total cash proceeds from sale of these refineries amounted to $950.0 million.

The results of these operations for the last three years are reflected in the following table.

(Millions of dollars)	**2013**	2012	2011
U.S. refining and marketing	**$ 134.8**	87.3	355.3
U.K. refining and marketing	**(119.2)**	52.2	(33.3)
U.K. exploration and production	**219.8**	24.9	11.5
Income from discontinued operations	**$ 235.4**	164.4	333.5

The U.S. refining and marketing (R&M) operations had better operating results in 2013 than 2012 primarily due to an impairment charge of $61.0 million in 2012 ($39.6 million after taxes) to writedown the carrying value of an ethanol plant. The U.K. R&M business incurred losses in 2013 following gains in 2012 due to both

significantly weaker margins at the Milford Haven, Wales refinery and a $73.0 million charge to writedown the carrying value of the U.K. assets at year-end 2013. The overall composite unit margin for the U.K. R&M business was a negative $0.75 per barrel in 2013, down from a positive $1.94 per barrel in 2012. The U.K. E&P results shown above include an after-tax gain on sale of $216.1 million in 2013, but operating profits were lower in 2013 than 2012 due to only a partial year of operations prior to the property sales in the current year versus a full year of operations in the prior year. In 2012, U.S. R&M results were significantly below 2011 due to a combination of lower retail marketing margins, unfavorable results, including the impairment charge noted above, for ethanol production operations in the later year, no repeat of U.S. refinery operating profits of $113.1 million from 2011, and a nonrecurring net gain after taxes of $18.7 million in 2011 on sale of the two refineries. The net gain from disposal of the two refineries included a gain on sale of the Superior refinery and associated inventories of $77.6 million and a loss on sale of the Meraux refinery and associated inventories of $58.9 million. The net gain on disposal was based on the selling prices of the refineries, plus the sales of all associated inventories at fair value, which was significantly above the last-in, first-out carrying value of these assets. U.K. R&M operations had much stronger results in 2012 compared to 2011 primarily due to stronger refining margins in the later year. Overall unit margins were a positive $1.94 per barrel in 2012 and a negative $0.67 per barrel in 2011. The higher operating results for the U.K. E&P business in 2012 compared to 2011 was mostly attributable to lower tax charges during the later year. In July 2012, the United Kingdom enacted tax changes that limited tax relief on oil and gas decommissioning costs to 50%, a reduction from the 62% tax relief previously allowed for these costs. This tax rate change led to a net reduction of income from this discontinued operation of $5.5 million in 2012. In 2011, the U.K. government enacted a 12% supplemental tax on oil and gas company profits in that country. This tax increase reduced income from discontinued operations in 2011 by $14.5 million, primarily to increase the recorded balance for deferred income taxes that will be paid in future years at the new higher rate. The 2011 rate change increased the effective tax rate to 62% for oil and gas operations in the U.K.

Capital Expenditures

As shown in the selected financial data on page 24 of this Form 10-K report, capital expenditures from continuing operations, including exploration expenditures, were $3.97 billion in 2013, compared to $4.19 billion in 2012, and $2.75 billion in 2011. These amounts excluded capital expenditures of $154.6 million in 2013, $190.9 million in 2012 and $190.6 million in 2011 related to discontinued operations, which were associated with U.K. refining and marketing operations held for sale at the end of 2013, U.S. retail marketing operations spun-off in August 2013, two U.S. petroleum refineries sold during 2011, and U.K. oil and gas assets sold in the first half of 2013. Capital expenditures included $435.3 million, $251.1 million and $371.2 million, respectively, in 2013, 2012 and 2011 for exploration costs that were expensed.

Capital expenditures for exploration and production continuing operations totaled $3.94 billion in 2013, $4.19 billion in 2012 and $2.75 billion in 2011. E&P capital expenditures in 2013 included $35.6 million for lease acquisitions, $493.7 million for exploration activities, and $3.41 billion for development projects. Lease acquisitions were primarily related to acreage extensions in the Eagle Ford Shale area. Exploration activities included exploratory drilling primarily in the Gulf of Mexico, Australia, Cameroon and Brunei. Exploratory activities also included seismic and other geophysical costs primarily in the U.S., Australia, Indonesia, Vietnam and West Africa. Development expenditures in 2013 included $1.48 billion for the drilling and completion program in the Eagle Ford Shale; $230.9 million for fields in