MURPHY OIL CORP /DE
Form 10-K
February 27, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES
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 No

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (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 No

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

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

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	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

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, 2014) – $11,804,954,783.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2015 was 177,501,534.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 13, 2015 have been incorporated by reference in Part III herein.

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. 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 four geographic segments, including the United States, Canada, Malaysia and all other countries. 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 Company has transitioned from an integrated oil company to an enterprise entirely focused on oil and gas exploration and production activities. The Company sold its retail marketing assets in the United Kingdom during 2014. The Company has shut down its oil refinery at Milford Haven, Wales, and is in the process of abandoning the facility at year-end 2014. 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."

At December 31, 2014, Murphy had 1,712 employees. Approximately 186 of these employees are currently working to abandon the closed Milford Haven refinery in the U.K. or in support of other operations to be sold in the U.K.

The information appearing in the 2014 Annual Report to Security Holders (2014 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-19 thru F-21, F-52 through F-63 and F-65 of this Form 10-K report and on pages 4 and 5 of the 2014 Annual Report (Exhibit 13 of this Form 10-K report).

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 2014, 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, Australia, Brunei, Cameroon, Vietnam, Equatorial Guinea, Suriname and Namibia 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 2014 was in the United States, Canada and Malaysia. MOCL owns a 5% undivided interest in Syncrude Canada Ltd. in northern Alberta. In December 2014 the Company sold 20% of its interests in Malaysia; a further sale of an additional 10% interest in Malaysia was completed in January 2015. Unless otherwise indicated, all references to the Company's oil, natural gas liquids and natural gas production volumes and proved crude oil, natural gas liquids and natural gas reserves are net to the Company's working interest excluding applicable royalties. Also, unless otherwise indicated, references to oil throughout this document could include crude oil, condensate and natural gas liquids where applicable volumes includes a combination of these products.

Murphy's worldwide crude oil, condensate and natural gas liquids production in 2014 averaged 151,647 barrels per day, an increase of 12% compared to 2013, and the highest oil volumes produced by the Company over an annual period. The increase in 2014 was primarily due to higher crude oil and natural gas liquids production in the Eagle Ford Shale area of South Texas. The Company's worldwide sales volume of natural gas averaged 446 million cubic feet (MMCF) per day in 2014, up 5% from 2013 levels. The increase in natural gas sales volume in 2014 was primarily attributable to higher gas production in the United States, where growth occurred due to further development drilling in the Eagle Ford Shale and start-up of the Dalmatian field in the Gulf of Mexico. Total worldwide 2014 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 225,973 barrels per day, an increase of 10% compared to 2013, and also a Company record for a single year. If the combined sale of 30% interest in Malaysia had occurred on January 1, 2014, total pro forma daily oil and natural gas production volumes would have been approximately 135,100 barrels and 386 MMCF, respectively, in 2014. The 30% production sold in late 2014 and early 2015 would have reduced 2014 production by approximately 26,600 barrels of oil equivalent per day (boepd), leaving a total of approximately 199,400 boepd of production in 2014 on a pro forma basis.

Total production in 2015 is currently expected to average between 195,000 and 207,000 boepd. The projected production decrease in 2015 is primarily due to the sale of 30% of Malaysia oil and gas assets near year-end 2014. Additionally, due to low oil and gas prices in early 2015, the Company expects to scale back 2015 drilling in the Eagle Ford Shale and Montney areas in North America, which will lead to an expected overall reduction in capital spending of approximately 38% compared to 2014.

United States

In the United States, Murphy primarily has production of crude oil, natural gas liquids and natural gas from fields in the Eagle Ford Shale area of South Texas and in the deepwater Gulf of Mexico. The Company produced approximately 68,300 barrels of crude oil and gas liquids per day and 88 MMCF of natural gas per day in the U.S. in 2014. These amounts represented 45% of the Company's total worldwide oil and 20% of worldwide natural gas production volumes. During 2014, 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 2014 was derived from four fields, including Dalmatian, Medusa, Front Runner and Thunder Hawk. The Company holds a 70% interest in Dalmatian in DeSoto Canyon Blocks 4 and 48, 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. During 2014, the Company acquired a 29.1% non-operated interest in the Kodiak field in Mississippi Canyon Blocks 727/771. Development at Kodiak is ongoing and first production is expected in early 2016. Total daily production in the Gulf of Mexico in 2014 was 16,800 barrels of oil and 54 MMCF of natural gas. Production in the Gulf of Mexico in 2015 is expected to total approximately 16,300 barrels of oil and gas liquids per day and 54 MMCF of natural gas per day. At December 31, 2014, Murphy has total proved reserves for Gulf of Mexico fields of 37.0 million barrels of oil and gas liquids and 90 billion cubic feet of natural gas.

The Company holds rights to approximately 152 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and gas play. In March 2015, the Company will reduce the number of active drilling rigs from five to four in the Eagle Ford Shale. Total 2014 oil and natural gas production in the Eagle Ford area was approximately 51,300 barrels per day and 33 MMCF per day, respectively. On a barrel of oil equivalent basis, Eagle Ford production accounted for 69% of total U.S. production volumes in 2014. Due to scale back of drilling and infrastructure development activities related to weak oil prices, production in the Eagle Ford Shale is expected to be flat in 2015. Eagle Ford production is expected to average approximately 51,000 barrels of oil and gas liquids per day and 37 MMCF of natural gas per day. At December 31, 2014, the Company's proved reserves in the Eagle Ford Shale area totaled 172.3 million barrels of crude oil, 24.7 million barrels of natural gas liquids, and 136 billion cubic feet of natural gas. Total U.S. proved reserves at December 31, 2014 were 204.9 million barrels of crude oil, 29.1 million barrels of natural gas liquids, and 226 billion cubic feet of natural gas.

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 wholly-owned heavy oil area and two wholly-owned 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 2014 was about 4,900 barrels of oil per day at Hibernia and 3,800 barrels per day at Terra Nova. Hibernia production declined in 2014 due to maturity of existing wells, while Terra Nova production was slightly higher in 2014. Oil production for 2015 at Hibernia and Terra Nova is anticipated to be approximately 5,100 barrels per day and 3,400 barrels per day, respectively. Total proved oil reserves at December 31, 2014 at Hibernia and Terra Nova were approximately 14.6 million barrels and 7.3 million barrels, respectively.

Murphy owns a 5% 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 2014 was about 12,000 net barrels of synthetic crude oil per day and is expected to average about 12,500 barrels per day in 2015. Total proved reserves for Syncrude at year-end 2014 were 105.6 million barrels.

Daily production in 2014 in the WCSB averaged 7,500 barrels of mostly heavy oil and 156 MMCF of natural gas. The Company has 117 thousand net acres of mineral rights in the Montney area, which includes the Tupper and Tupper West natural gas producing areas. Natural gas production commenced at Tupper in December 2008, while Tupper West production started up in February 2011. The Company has 268 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 2015 in Western Canada, excluding Syncrude, is expected to average 5,400 barrels and 173,000 MMCF, respectively. The decrease in oil production in 2015 is expected due to well declines and selective well shut-ins caused by currently low heavy oil prices in the Seal area. The increase in natural gas volumes in 2015 is primarily the result of new wells brought on line in the Tupper and Tupper West areas in late 2014 and early 2015. Total WCSB proved liquids and natural gas reserves at December 31, 2014, excluding Syncrude, were 16.3 million barrels and 825 billion cubic feet, respectively.

Malaysia

In Malaysia, the Company has majority interests in eight 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 2.62 million gross acres. In December 2014, the Company completed the sale of 20% of its interest in most Malaysian oil and gas assets. The Company additionally sold another 10% of its interest in January 2015. The working interest percentages herein reflect reduced interests following the full sale of 30% of interests, including the final 10% sale completed in 2015. Proved reserves totals presented as of December 31, 2014 reflect only the 20% interest sold in December 2014. An additional reduction of Malaysia proved reserves will occur in 2015 to reflect the additional 10% interest sale in January 2015.

Murphy has a 59.5% 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 offshore platforms and pipelines tying back to the Company's existing infrastructure. Approximately 21,100 barrels of oil and gas liquids per day were produced in 2014 at Blocks SK 309/311. Oil and gas liquids production in 2015 at fields in Blocks SK 309/311 is anticipated to total about 15,600 barrels of oil per day, with the reduction from 2014 primarily related to the 30% sale. 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 169 MMCF per day during 2014 (gross 266 MMCF per day). Sarawak net natural gas sales volumes are anticipated to be approximately 109 MMCF per day in 2015, with the reduction primarily attributable to the 30% sale. Total proved reserves of liquids and natural gas at December 31, 2014 for Blocks SK 309/311 were 17.6 million barrels and 241 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 in 2009. The Company has a 56% interest in Block K discovered fields, which include Kikeh, Kakap-Gumusut (hereafter "Kakap") and Siakap North-Petai (hereafter "Siakap"). Total gross acreage held by the Company in Block K as of December 31, 2014 was approximately 82,000 acres. Production volumes at Kikeh averaged approximately 24,200 barrels of oil per day during 2014. Oil production at Kikeh is anticipated to average approximately 13,700 barrels per day in 2015. The reduction in Kikeh oil production in 2015 is primarily attributable to the 30% interest sell down, but also is impacted by overall field decline. The Kakap field in Block K is operated by another company. The Kakap field was jointly developed with the Gumusut field owned by others and Murphy holds a 9.8% working interest in the unitized development. Early production began in late 2012 at Kakap via a temporary tie-back to the Kikeh production facility. The primary Kakap main field production facility was completed and full-field production started up in October 2014. Kakap oil production in 2014 totaled about 4,400 net barrels of oil per day. In 2015, Kakap production is expected to average near 6,200 barrels of oil per day. The Siakap oil discovery was developed as a unitized area operated by Murphy, with a tie-back to the Kikeh field. Production began in 2014 at Siakap, and daily production averaged near 5,400 barrels of oil for the whole year at this field. In 2015, Siakap field production is expected to average 5,000 barrels of oil per day. The Company has a Block K natural gas sales contract with PETRONAS that calls for gross sales volumes of up to 120 MMCF per day. Gas production in Block K will continue until the earlier of lack of available commercial quantities of associated gas reserves or expiry of the Block K production sharing contract. Natural gas production in Block K in 2014 totaled approximately 32 MMCF per day. Daily gas production in 2015 in Block K is expected to average about 27 MMCF per day. Total proved reserves booked in Block K as of year-end 2014 were 77 million barrels of crude oil and 55 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. The Company followed up Rotan with several other nearby discoveries. Following the partial sell down, Murphy's interests in Block H range between 42% and 56%. Total gross acreage held by the Company at year-end 2014 in Block H was 15.99 million acres. In early 2014, PETRONAS and the Company sanctioned a Floating Liquefied Natural Gas (FLNG) project for Block H, and agreed terms for sales of natural gas to be produced with prices tied to an oil index. First production is expected at Block H in 2018. At December 31, 2014, total natural gas proved reserves for Block H were 340 billion cubic feet.

The Company has a 42% 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 interest in shallow-water Malaysia Block SK 314A. The production sharing contract covers a three year exploration period. The Company's working interest in Block SK 314A is 59.5%. This block includes 1.12 million gross acres. The Company has a 70% carry of a 15% partner in this concession through the minimum work program. The first exploration wells are planned in 2015 for this block.

In February 2015, the Company acquired a 50% interest in the offshore Block SK 2C. The Company operates the block, which includes 1.08 million gross acres. The concession carries one well commitment during the one-year exploration period. At the expiration of the first exploration period, the Company can opt to extend for two additional years by agreeing to drill another well.

Murphy has a 75% interest in gas holding agreements for Kenarong and Pertang discoveries made in Block PM 311 located offshore peninsular Malaysia. An application for an extension of a gas holding agreement was presented to PETRONAS in 2014, but the application was rejected. Due to the uncertainty of the future production of the gas discovered in Block PM 311, the Company wrote off the prior-year well costs of $47.4 million related to Kenarong and Pertang in 2014. The Company never included proved reserves of natural gas for Block PM 311 in its proved reserves.

Australia

In Australia, the Company holds eight offshore exploration permits and serves as operator of six of them.

The first permit was acquired in 2007 with a 40% interest in Block AC/P36 in the Browse Basin. Murphy 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. In 2012, Murphy increased its working interest in the remaining acreage to 100% and subsequently farmed out a 50% working interest and operatorship. The existing work commitment for this license includes further geophysical work.

In June 2009, Murphy acquired a 70% interest and operatorship in Block NT/P80 in the Bonaparte Basin. In 2013 Murphy acquired 3D seismic data over the block with further work commitments of geophysical studies required under this license.

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 thousand gross acres. The WA-476-P permit has a primary term work commitment consisting of seismic data purchase and geophysical studies, and all primary term commitments have been completed for this permit.

The Company also acquired permit WA-481-P in the Perth Basin, offshore Western Australia, in August 2012. Murphy holds a 40% working interest and operatorship of the permit, which covers approximately 4.30 million gross acres. The work commitment calls for 2D and 3D seismic acquisition and processing, geophysical work and three exploration wells, which are expected to be drilled in the first half of 2015. The first exploration well was being drilled in February 2015.

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 thousand gross acres. Two wells were drilled on the license in 2013. The first well found hydrocarbon but was deemed commercially unsuccessful and was written off to expense. The second well was also unsuccessful and costs were expensed.

The Company was awarded permit EPP43 in the Ceduna Basin, offshore South Australia, in October 2013. The Company operates the concession and holds a 50% working interest in the permit covering approximately 4.08 million gross acres. The exploration permit has commitments for 2D and 3D seismic, which was in the process of being shot in early 2015.

In April 2014 and June 2014, Murphy was awarded licenses AC/P57 and AC/P58 in the Vulcan Sub Basin, offshore Western Australia. The respective blocks cover approximately 82 thousand and 692 thousand gross acres. These exploration permits cover six years each and require 3D seismic reprocessing and a gravity survey.

Indonesia

The Company currently has interests in two exploration licenses in Indonesia and serves as operator of these concessions. 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 1.22 million gross acres. The three-year work commitment called for seismic acquisition and processing, which the Company completed in 2013. The Company expects to relinquish this license in 2015.

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, and the agreement called for work commitments of seismic acquisition and processing, which were undertaken in 2014. The Company anticipates relinquishing this license in 2015.

In November 2008, Murphy entered into a production sharing contract in the Semai II block, offshore West Papua. The Company had a 28.3% interest in the block which covered about 543 thousand gross acres after a required partial relinquishment of acreage during 2012. The permit called 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 were drilled in 2014 and were also unsuccessful. The Company relinquished this license in 2014.

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 covered approximately 745 thousand gross acres. The contract granted a six-year exploration term with an optional four-year extension. The Company relinquished this license 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 these blocks.

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. This concession carries a three-well commitment.

In early 2014, the Company farmed into Block 13-03. The Company has a 20% working interest in this concession which covers 853 thousand gross acres. Murphy expensed an unsuccessful exploration well drilled in the block in 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. In early 2014, Murphy farmed out a portion of its working interest in Block 48, thereby reducing its interest from 100% to 50% and in early 2015 Murphy relinquished its license in this block.

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 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, the Company drilled an unsuccessful exploration well on the Ntem prospect in 2014. The Company declared force majeure again in May 2014. The Company intends to withdraw from this block in 2015.

In October 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 an unsuccessful shallow well. The initial exploration period was extended for two years through March 2015 with an obligation for one well. Murphy drilled an unsuccessful deepwater well in the block in 2013 as part of the obligations under the agreement. The Company relinquished its interest in this license in 2014.

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 in April 2013. The block is located offshore mainland Equatorial Guinea and encompasses 557 thousand gross acres with water depths ranging from 1,200 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 the extension carries an obligation to drill one well. Entering into the second sub-period carries an 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.

Namibia

In March 2014, the Company acquired a 40% working interest and operatorship of Blocks 2613 A/B. The Company acquired the working interest through a farm-out arrangement under the existing petroleum agreement entered into in October 2011. The block encompasses 2,734 thousand gross acres with water depths ranging from 400 to 2,500 meters. The initial exploration period of four years may be extended one year. Entering the first renewal period has the obligation to drill an exploration well. Entering the second renewal period has the obligation to drill an additional well. In 2014, Murphy completed acquisition of new 3D seismic over the 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 shut down and ceased production in the fourth quarter of 2013 and abandonment operations were completed in 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 decommissioned the Azurite field upon completion of abandonment in 2014 and has exited the country.

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.

Ecuador – Discontinued Operations

Murphy sold its 20% working interest in Block 16, Ecuador in March 2009. 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 arbitral body 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 before a different arbitral body. The arbitration proceeding was held in late 2014 and 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 reserves for crude oil, synthetic oil, natural gas liquids and natural gas as of December 31, 2014 are presented in the following table.

	Proved Reserves			
	Crude Oil	Synthetic Oil	Natural Gas Liquids	Natural Gas
Proved Developed Reserves:	(millions of barrels)			(billions of cubic feet)
United States	106.2	–	16.5	145.6
Canada	32.4	105.6	0.2	467.4
Malaysia	79.9	–	0.8	199.1
Total proved developed reserves	218.5	105.6	17.5	812.1
Proved Undeveloped Reserves:				
United States	98.7	–	12.6	80.7
Canada	5.0	–	0.5	375.4
Malaysia	14.0	–	–	436.5
Total proved undeveloped reserves	117.7	–	13.1	892.6
Total proved reserves	336.2	105.6	30.6	1,704.7

Murphy Oil's proved undeveloped reserves increased during 2014 as presented in the table that follows:

(Millions of oil equivalent barrels)	Total Proved	Total Proved Undeveloped
Proved undeveloped reserves:		
Beginning of year	687.9	252.7
Revisions of previous estimates	23.7	8.3
Improved recovery	8.6	–
Extension and discoveries	163.4	123.8
Conversion to proved developed reserves	–	(90.6)
Purchases of properties	7.0	7.0
Sales of properties	(51.6)	(21.7)
Production	(82.5)	–
End of year	756.5	279.5

During 2014, Murphy added proved reserves of 202.7 million barrels of oil equivalent (mmboe). The most significant adds were in Block H Malaysia where a newly sanctioned floating liquefied natural gas project added 70.9 mmboe, drilling and well performance in the Montney gas area of Western Canada that added 56.2 mmboe, and drilling and well performance in the Eagle Ford Shale that added 37.9 mmboe. The Company sold 20% of its oil and gas assets in Malaysia and other various fields during the year which reduced its proved reserves by 51.6 mmboe.

Murphy's total proved undeveloped reserves at December 31, 2014 increased 26.8 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 2014 was predominantly attributable to three areas – drilling in the Eagle Ford Shale area of South Texas and the Montney area in Western Canada as these areas had active development work ongoing during the year, and the sanction of a development plan for Block H Malaysia during 2014. The majority of proved undeveloped reserves additions associated with revisions of previous estimates were the result of improved completion design and increased fracturing size at Tupper and Tupper West in the Montney area. The majority of the proved undeveloped reserves migration to the proved developed category occurred in the Eagle Ford Shale and Block K Malaysia. The approval of the development plan for Block H Malaysia added proved undeveloped reserves of 70.9 MMBOE during 2014. The Company sold 20% of its Malaysia oil and gas properties in late 2014, which led to a reduction of proved undeveloped reserves of 21.7 MMBOE during the year. The Company spent approximately $2.2 billion in 2014 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend about $1.2 billion in 2015, $1.5 billion in 2016 and $1.6 billion in 2017 to move currently undeveloped proved reserves to the developed category. The anticipated level of spend in 2015 includes 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, 2014, proved reserves are included for several development projects, including oil developments at the Eagle Ford Shale in South Texas and the Kakap, Kikeh and Siakap fields, offshore Sabah, Malaysia, as well as natural gas developments offshore Sarawak and offshore Block H, Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2014 were approximately 279 MMBOE, which is 37% of the Company's total proved reserves. Certain development projects have proved undeveloped reserves that will take more than five years to bring to production. Two 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 2014. 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 second 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 2014. This project is an extension of the Sarawak natural gas project and is expected to be on production in 2015 once current project production volumes decline. The Block H development project has undeveloped proved reserves that make up 7% of the Company's total proved reserves at year-end 2014. This operated project will take longer than five years from discovery to completely develop due to construction of floating LNG facilities and the remote location offshore deep waters in Sabah Malaysia. Field start up is expected to occur in 2018, which is less than five years beyond the period that proved undeveloped reserves were recorded.

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 the Senior Vice President, Corporate Planning & Services, 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.

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 work over 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 the Form 10-K report.

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 reserves of crude oil, natural gas liquids and natural gas for the last three years are presented by geographic area on pages F-54 through F-60 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 natural 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, 2014 are shown on pages 4 and 5 of the 2014 Annual Report (Exhibit 13 of this Form 10-K report). In 2014, 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 34 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.

Supplemental disclosures relating to oil and gas producing activities are reported on pages F-52 through F-65 of this Form 10-K report.

At December 31, 2014, 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	82	77	70	66	152	143
– Gulf of Mexico	14	6	942	590	956	596
Total United States	96	83	1,012	656	1,108	739
Canada – Onshore, excluding oil sands	77	76	510	493	587	569
– Offshore	105	9	43	2	148	11
– Oil sands – Syncrude	96	5	160	8	256	13
Total Canada	278	90	713	503	991	593
Malaysia	260	174	2,362	1,391	2,622	1,565
Australia	–	–	11,430	5,567	11,430	5,567
Brunei	–	–	2,934	519	2,934	519
Indonesia	–	–	2,097	2,097	2,097	2,097
Vietnam	–	–	5,951	3,450	5,951	3,450
Namibia	–	–	2,734	1,094	2,734	1,094
Cameroon	–	–	573	287	573	287
Equatorial Guinea	–	–	557	251	557	251
Suriname	–	–	794	397	794	397
Spain	–	–	36	6	36	6
Totals	634	347	31,193	16,218	31,827	16,565

Certain acreage held by the Company will expire in the next three years. Scheduled expirations in 2015 include 80 thousand net acres in SK Blocks 309 and 311 in Malaysia; 50 thousand net acres in Block H in Malaysia; 96 thousand net acres in Block SK 314A in Malaysia; 147 thousand net acres in Western Canada; 171 thousand net acres in Block 13-03 in Vietnam; 46 thousand net acres in the United States; 72 thousand net acres in Cameroon; and 397 thousand net acres in Block 48 Suriname. Scheduled acreage expirations in 2016 include 1,224 thousand net acres in Wokam II Block in Indonesia; 670 thousand net acres in Block SK 314A in Malaysia; 421 thousand net acres in Block NT/P80 Australia; 42 thousand net acres in Block WA-408-P Australia; 575 thousand net acres in Blocks 144 and 145 in Vietnam; 81 thousand net acres in Block 11-2/11 in Vietnam; 121 thousand net acres in the United States; and 93 thousand net acres in Western Canada. Acreage currently scheduled to expire in 2017 include 873 thousand net acres in Semai IV Block in Indonesia; 547 thousand net acres in Blocks 2613A and 2613B in Namibia; 50 thousand net acres in the United States; and 41 thousand net acres in Western Canada.

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, 2014.

	Oil Wells		Gas Wells	
	Gross	Net	Gross	Net
Country				
United States	633	503	16	12
Canada	432	389	213	213
Malaysia	85	65	49	42
Totals	1,150	957	278	267

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
2014										
Exploratory	1.0	0.8	-	-	-	-	-	1.9	1.0	2.7
Development	187.2	-	48.0	11.0	16.2	-	-	-	251.4	11.0
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

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, 2014 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, other than one exploratory well being drilled in the Gulf of Mexico.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States	1	0.4	78	67.0	79	67.4
Canada	–	–	5	5.0	5	5.0
Malaysia	–	–	5	3.3	5	3.3
Totals	1	0.4	88	75.3	89	75.7

Refining and Marketing – Discontinued Operations

The Company completed the separation of its former retail marketing business in the United States on August 30, 2013, through a distribution of 100% of the shares of Murphy USA Inc. (MUSA) to shareholders of Murphy Oil. MUSA is a stand-alone, publicly owned company which is listed on the New York Stock Exchange under the ticker symbol “MUSA.”

On September 30, 2014, the Company sold its retail marketing business in the United Kingdom. The Company also is attempting to sell its U.K. finished products terminal business during 2015. Despite great effort, the Company was unable to sell its Milford Haven, Wales, crude oil refinery, and instead is in the process of decommissioning the processing units at year-end 2014. The U.K. terminal business consists of three inland terminals and one waterborne terminal adjacent to the now shuttered Milford Haven refinery.

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.

Environmental

Murphy’s businesses are subject to various international, national, state, provincial and local environmental laws and regulations that govern the manner in which the Company conducts its operations. The Company anticipates that these requirements will continue to become more complex and stringent in the future.

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 45 and 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, and independent producers of oil and natural gas. Virtually all of the state-owned and major integrated oil companies and many of the independent producers 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 reserves of crude oil, natural gas liquids (NGL) and natural gas included in this report on pages F-54 through F-60 have been prepared by qualified Company personnel or qualified independent engineers based on an unweighted average of crude oil, NGL and natural gas prices in effect at the beginning of each month of the respective year 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 crude oil, NGL 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.

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, 2014, approximately 27% of the Company's crude oil proved reserves, 43% of natural gas liquids proved reserves and 52% of natural gas proved 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-64 and F-65 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 crude oil, natural gas liquids and natural gas 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 $93 per barrel in 2014, compared to $98 per barrel in 2013 and $94 per barrel in 2012. As demonstrated by the significant decline in WTI crude oil prices in late 2014, prices can be quite volatile. The average sales price of WTI crude oil was slightly above $59 per barrel in December 2014, but it fell to slightly more than $47 in January 2015. The average NYMEX natural gas sales price was $4.34 per thousand cubic feet (MCF) in 2014, up from $3.73 per MCF in 2013 and $2.83 per MCF in 2012. The average NYMEX price in January 2015 was approximately $3.00 per MCF. As demonstrated in 2012 through 2014, the sales prices for crude 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.

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 2014, significant wildcat wells were primarily drilled offshore Cameroon, Indonesia, Vietnam and in the Gulf of Mexico. The Company's 2015 planned exploratory drilling program includes wells offshore in the Gulf of Mexico, Malaysia, Australia and Brunei.

Potential federal or state regulations regarding hydraulic fracturing could increase the Company's costs and/or restrict operating methods, which could adversely affect its 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 in North America. 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 additional 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 unlawful, less effective or drive up its costs. If any such action is taken in the future, the Company's production levels could be adversely affected or its costs of drilling and completion could be increased.

Hydraulic fracturing exposes the Company to operational and regulatory risks.

Hydraulic fracturing operations subject the Company to operational risks inherent in the drilling and production of oil and natural gas. These risks include underground migration or surface spillage due to releases of oil, natural gas, formation water or well fluids, as well as any related surface or ground water contamination, including from petroleum constituents or hydraulic fracturing chemical additives. Ineffective containment of surface spillage and surface or ground water contamination resulting from hydraulic fracturing operations, including from petroleum constituents or hydraulic fracturing chemical additives, could result in environmental pollution, remediation expenses and third party claims alleging damages, which could adversely affect the Company's financial condition and results of operations. In addition, hydraulic fracturing requires significant quantities of water. Any diminished access to water for use in the process could curtail the Company's operations or otherwise result in operational delays or increased costs.

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 has a capacity of $2.0 billion and matures 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 liquids and natural gas, for which the Company has little or no influence on the sales prices or regional and worldwide consumer demand for these products. Changes in commodity prices also impact the volume of production attributed to the Company under production sharing contracts in Malaysia. 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 and natural gas for a period of time. An oversupply of crude oil in late 2014 led to a severe decline in worldwide oil prices. 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. The current low crude oil price environment in late 2014 and early 2015 has caused the Company to reduce discretionary drilling programs, which in turn, hurts the Company's future production levels and future cash flow generated from operations.

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 2014, approximately 15% of the Company's total production was at fields operated by others, while at December 31, 2014, approximately 23% 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, 2014, approximately 27% of the Company's 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.

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 effect 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.

With the exit of its former downstream operations, Murphy will have fewer cash flow generating assets to service its debt.

During the past several years, the Company has essentially exited the refining and marketing business through various means, including a distribution to shareholders, outright sale and asset closure. Murphy, therefore, no longer has the cash flow generated from these assets to make interest and principal payments on its debt. If Murphy's remaining exploration and production business is not successful as a standalone 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 most remaining U.K. 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 Canada, certain crude oil sales are priced in U.S. dollars, and in the U.K., certain bulk finished products 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 periodically 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. 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 L 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.

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, 2014.

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-52 to F-65 and in Note E – Property, Plant and Equipment beginning on page F-19.

Executive Officers of the Registrant

Present corporate office, length of service in office and age at February 1, 2015 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 53; 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.

Kevin G. Fitzgerald – Age 59; 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. Mr. Fitzgerald is scheduled to retire from the Company on March 1, 2015. As previously announced by the Company, John W. Eckart, presently Senior Vice President and Controller, has been appointed Executive Vice President and Chief Financial Officer upon the retirement of Mr. Fitzgerald.

Walter K. Compton – Age 52; 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.

Bill H. Stobaugh – Age 63; Executive Vice President since February 2012. Mr. Stobaugh was Senior Vice President from February 2005 to January 2012. Mr. Stobaugh has announced his retirement from the Company effective March 1, 2015.

John W. Eckart – Age 56; 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. As previously noted, Mr. Eckart has been appointed Executive Vice President and Chief Financial Officer effective March 1, 2015.

Kelli M. Hammock – Age 43; Senior Vice President, Administration since February 2014. Ms. Hammock was Vice President, Administration from December 2009 to February 2014.

Tim F. Butler – Age 52; Vice President, Tax since August 2013. Mr. Butler was General Manager, Worldwide Taxation from August 2007 to August 2013.

John W. Dumas – Age 60; 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 56; 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.

Allan J. Misner – Age 48; Vice President, Internal Audit since February 2014. Mr. Misner served as Director, Internal Audit from 2007 to 2014.

K. Todd Montgomery – Age 50; Vice President, Corporate Planning & Services since February 2014. Mr. Montgomery joined the Company in 2014 as Vice President, Corporate Planning & Services 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. Effective March 1, 2015, Mr. Montgomery will be promoted to Senior Vice President.

E. Ted Botner – Age 50; Secretary and Manager, Law since August 2013. Mr. Botner 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. Effective March 1, 2015, Mr. Botner will be promoted to Vice President, Law and Secretary.

John B. Gardner – Age 46; 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. Effective March 1, 2015, Mr. Gardner will be promoted to Vice President and Treasurer.

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.

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 2,556 stockholders of record as of December 31, 2014. Information as to high and low market prices per share and dividends per share by quarter for 2014 and 2013 are reported on page F-66 of this Form 10-K report.

Murphy Oil Corporation

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	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*
October 1, 2014 to October 31, 2014	-	$ -	-	$ 500,000,000
November 1, 2014 to November 30, 2014	-	-	-	500,000,000
December 1, 2014 to December 31, 2014	-	-	-	500,000,000
Total October 1, 2014 to December 31, 2014	-	-	-	$ 500,000,000

*On August 6, 2014, the Company's Board of Directors authorized a buyback of up to $500 million of the Company's Common stock through August 2015. Through the filing of this Form 10-K report, the Company had not repurchased any Common stock under this Board approved stock buyback program. The Company may utilize a number of different methods to effect the repurchases, including but not limited to, open market purchases, accelerated share repurchases and negotiated block purchases, and some of the repurchases may be effected through Rule 10b5-1 plans. The timing and amount of repurchases will depend upon several factors, including market, financing and business conditions, and the repurchases may be discontinued at any time.

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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, 2009 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 report and it is not incorporated into any document that incorporates this Form 10-K report by reference.

	2009	2010	2011	2012	2013	2014
Murphy Oil Corporation	$ 100	140	107	122	157	125
S&P 500 Index	100	115	117	136	176	201
NYSE Arca Oil Index	100	117	122	127	155	143

Item 6. SELECTED FINANCIAL DATA

	2014	2013	2012	2011	2010
(Thousands of dollars except per share data)					
Results of Operations for the Year					
Sales and other operating revenues	$ 5,288,933	5,312,686	4,608,563	4,222,520	3,556,461
Net cash provided by continuing operations	3,048,639	3,210,695	2,911,380	1,688,884	2,491,017
Income from continuing operations	1,024,973	888,137	806,494	539,198	618,493
Net income	905,611	1,123,473	970,876	872,702	798,081
Per Common share – diluted					
Income from continuing operations	$ 5.69	4.69	4.14	2.77	3.20
Net income	5.03	5.94	4.99	4.49	4.13
Cash dividends per Common share	1.325	1.25	3.675 [1]	1.10	1.05
Percentage return on[2]					
Average stockholders’ equity	10.8	12.5	10.5	9.9	10.3
Average borrowed and invested capital	8.4	10.3	9.6	9.2	9.4
Average total assets	5.1	6.3	6.2	5.7	5.9
Capital Expenditures for the Year[3]					
Continuing operations					
Exploration and production	$ 3,742,541	3,943,956 [4]	4,185,028	2,748,008	2,023,309
Corporate and other	14,453	22,014	8,077	5,218	5,899
	3,756,994	3,965,970	4,193,105	2,753,226	2,029,208
Discontinued operations	12,349	154,622	190,881	190,586	418,932
	$ 3,769,343	4,120,592	4,383,986	2,943,812	2,448,140
Financial Condition at December 31					
Current ratio	1.04	1.09	1.21	1.22	1.21
Working capital	$ 131,262	284,612	699,502	622,743	619,783
Net property, plant and equipment	13,331,047	13,481,055	13,011,606	10,475,149	10,367,847
Total assets	16,742,307	17,509,484	17,522,643	14,138,138	14,233,243
Long-term debt	2,536,238	2,936,563	2,245,201	249,553	939,350
Stockholders’ equity	8,573,434	8,595,730	8,942,035	8,778,397	8,199,550
Per share	48.30	46.87	46.91	45.31	42.52
Long-term debt – percent of capital employed[2]	22.8	25.5	20.1	2.8	10.3

[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). The Company consistently discloses these financial measures because it believes its 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:

n 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.

n 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.

n 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.

n 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.

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. 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 2014 were as follows:

· Announced the sale of 30% of its interest in Malaysia assets for a price of $2.0 billion, subject to customary closing costs and adjustments for the period from the January 1, 2014 effective date to the respective closing dates. The Company completed the sale of 20% of these interest on December 18, 2014 and closed the sale of the remaining 10% on January 29, 2015.

· Produced a Company record near 226,000 barrels of oil equivalent per day.

· Ended 2014 with a Company record level of proved reserves, totaling 756.5 million barrels of oil equivalent, and replaced proved reserves equal to 183% of production on a barrel of oil equivalent basis during the year.

· Started-up three new deepwater fields, including Siakap North and Kakap in Malaysia and Dalmatian in the Gulf of Mexico.

· Sanctioned the Block H floating liquefied natural gas project offshore Sabah Malaysia.

· Completed the sale of U.K. retail marketing operations on September 30, 2014.

· Continued its transition to a pure play exploration and production company by beginning the abandonment of the Milford Haven, Wales refinery following an unsuccessful attempt to sell the facility.

· Repurchased 6.37 million Common shares at a cost of $375 million.

In 2014, the Company completed the sale of its U.K. retail marketing operations, and later in 2014 began decommissioning activities at the Milford Haven, Wales refinery following an unsuccessful attempt to sell the facility. A sale of the U.K. finished products terminals and the decommissioning of the Milford Haven refinery facility would complete the Company's transition to an independent oil and gas company.

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."

Both the U.S. and U.K. downstream businesses are 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's continuing operations generate revenue by producing crude oil, natural gas liquids (NGL) and natural gas in the United States, Canada and Malaysia and then selling these products to customers. The Company's revenue is highly affected by the prices of crude oil, natural gas and NGL. 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 67% 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 2014. In 2015, the Company's ratio of hydrocarbon production represented by oil is expected to again represent two-thirds of total production. When oil-price linked natural gas in Malaysia is combined with oil production, the Company's 2015 total expected production is approximately 76% linked to the price of oil. If the prices for crude oil and natural gas remains weak in 2015 or beyond, this will have an unfavorable impact on the Company's operating profits. As described on page 54, the Company has entered into forward delivery contracts that will reduce its exposure to changes in natural gas prices for approximately 40% of the natural gas it expects to produce in Western Canada in 2015.

Oil prices weakened in 2014 compared to the prior year, while North American natural gas prices were higher in 2014 than 2013. The sales price for a barrel of West Texas Intermediate (WTI) crude oil averaged $93.00 in 2014, $98.05 in 2013 and $94.15 in 2012. The sales price for a barrel of Platts Dated Brent crude oil declined to $99.00 per barrel in 2014, following averages of $108.66 per barrel and $111.67 per barrel in 2013 and 2012, respectively. While the WTI index saw a 5% decrease in 2014, Dated Brent fell back by 9% compared to 2013. During 2014 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 $6.00 per barrel during 2014, compared to $10.61 per barrel in 2013 and $17.52 per barrel in 2012. Worldwide oil prices began to weaken in the fall of 2014 and continued to soften throughout the early winter season. The softening of prices in late 2014 caused average oil prices for the year to be below the average levels achieved in 2013. During 2013, worldwide oil prices were generally comparable to 2012, while the sales price for natural gas produced in North America was improved compared to the prior year. The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $4.33 in 2014, $3.73 in 2013 and $2.83 in 2012. NYMEX natural gas prices in 2014 were 16% above the average price experienced in 2013, with the price increase generally caused by colder average winter season temperatures in North America in the later year. NYMEX natural gas prices had 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. On an energy equivalent basis, the market continued to discount North American natural gas and NGL compared to crude oil in 2014. Crude oil prices in early 2015 have been significantly below the 2014 average prices, and natural gas prices in North America in 2015 have thus far been well below the 2014 levels due to warmer than normal temperatures across much of the Northern U.S. during the early winter season of 2014-2015.

During 2014, the Company sold its U.K. retail marketing assets as well as 20% of its oil and gas assets in Malaysia. Following these sales, the Company repatriated cash from the U.K. and Malaysia of $250 million and $1.7 billion, respectively. Foreign tax credits were available to cover most of the U.S. income taxes associated with these repatriated funds.

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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)		2014	2013	2012
Net income	$	905.6	1,123.5	970.9
Diluted EPS		5.03	5.94	4.99
Income from continuing operations	$	1,025.0	888.1	806.5
Diluted EPS		5.69	4.69	4.14
Income (loss) from discontinued operations	$	(119.4)	235.4	164.4
Diluted EPS		(0.66)	1.25	0.85

Murphy Oil's net income in 2014 was 19% lower than 2013, primarily due to an unfavorable variance in the results of discontinued operations between years. In August 2013, the Company distributed to its shareholders through a spin-off transaction all of the U.S. retail marketing operations. This business generated after-tax income of $134.8 million in 2013. Additionally, in early 2013, the Company sold all of its U.K. oil and gas assets, which including a gain on the disposal, generated income of $219.8 million in 2013. In 2014 and 2013, the Company's U.K. refining and marketing operations generated losses of $120.6 million and $119.2 million, respectively. Income from continuing operations in 2014 exceeded 2013 results by 15%. The current year included a $321.4 million after-tax gain on sale of 20% of the Company's oil and gas assets in Malaysia. Excluding this gain in Malaysia, profits from continuing operations in 2014 were $184.5 million below the prior year, primarily due to lower average realized oil sales prices during 2014.

The Company'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% in 2013 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 2013 improvement in discontinued operations results by 43% was attributable to a gain on sale of U.K. oil and gas assets and better profits for U.S. retail marketing operations, but U.K. downstream results were significantly below 2012 levels.

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

2014 vs. 2013 – Net income in 2014 totaled $905.6 million ($5.03 per diluted share) compared to 2013 net income of $1,123.5 million ($5.94 per diluted share). Income from continuing operations increased in 2014, amounting to $1,025.0 million ($5.69 per diluted share), while 2013 amounted to $888.1 million ($4.69 per diluted share). The 2014 increase for continuing operations was primarily associated with a $321.4 million after-tax gain generated from sale of 20% of oil and gas assets in Malaysia. Additionally, the Company's earnings in 2014 benefited from sale of 10% more oil and 5% more natural gas compared to 2013, but the average realized sales price for crude oil was 8% lower in 2014 compared to the prior year. Higher oil and gas production volumes led to higher overall extraction costs in 2014, plus the significant weakening of oil and gas prices in late 2014 led to higher impairment expense in the current year. Net interest expense was higher in 2014 compared to the prior year due to a combination of more borrowings and lower amounts capitalized to oil and gas development projects. The 2014 results were favorably affected by slightly higher tax benefits associated with foreign exploration activities and lower overall administrative costs. The results of discontinued operations were a loss of $119.4 million ($0.66 per diluted share) in 2014 compared to earnings of $235.4 million ($1.25 per diluted share) in 2013. The prior year's results for discontinued operations included a $216.1 million after-tax gain on sale of U.K. oil and gas properties as well as profitable operating results of $134.8 million from U.S. retail marketing operations that were spun-off to shareholders in August 2013. The losses generated by U.K. refining and marketing operations were similar in both years.

Sales and other operating revenues in 2014 were $23.8 million below 2013 as higher oil and natural gas sales volumes in the current year were more than offset by weaker oil sales prices compared to the prior year. Sales volumes grew by 8.5% in 2014 on a barrel of oil equivalent basis, but average crude oil sales prices realized in 2014 fell by 8% compared to the prior year. The overall increase in sales volumes was mostly attributable to growth in the Eagle Ford Shale in South Texas. Oil prices declined sharply in late 2014 (with further weakening in early 2015) due to an oversupply of crude oil available on a worldwide scale. Gain on sale of assets was $139.0 million higher in 2014, primarily associated with a pretax gain of $144.8 million generated on sale of 20% of the Company's oil and gas assets in Malaysia in December 2014. Interest and other income in 2014 was $29.2 million below 2013 levels primarily due to lower profits realized on changes in foreign exchange rates during the current year. Lease operating expenses declined $162.9 million in 2014 compared to 2013 essentially due to nonrecurring costs in the prior year upon shut down of oil production operations in Republic of the Congo. Severance and ad valorem taxes increased by $19.9 million in 2014 caused by higher volume of oil produced and a higher well count in the Eagle Ford Shale. Exploration expenses increased $11.4 million in 2014 compared to the prior year primarily due to higher amortization costs associated with Eagle Ford Shale leaseholds. Higher costs in 2014 for exploratory drilling were mostly offset by lower seismic costs compared to the prior year. Selling and general expense was reduced by $15.2 million in 2014 compared to the prior year mostly related to nonrecurring costs in 2013 associated with the spin-off of the U.S. retail marketing business to shareholders. Depreciation, depletion and amortization expense rose $352.9 million in 2014 due to both higher overall oil and natural gas production levels and higher per-unit capital amortization rates in areas where production growth was achieved. Impairment expense associated with asset writedowns increased $29.7 million in 2014 primarily due to non-recoverability of goodwill for conventional operations in Canada that was originally recorded in association with an oil and gas company acquisition in 2000. Accretion expense increased $1.8 million in 2014 primarily due to added levels of discounted asset retirement liabilities associated with development drilling in the Gulf of Mexico. Interest expense in 2014 was $12.0 million more than the prior year due to higher average borrowing levels compared to 2013. Interest costs capitalized in 2014 were $31.9 million below 2013 levels due to fewer ongoing oil development projects during the just completed year. Other operating expense was $24.9 million in 2014 and primarily included costs associated with write-down of materials inventory in Malaysia. Income tax expense was $357.3 million lower in 2014 compared to the prior year due to a combination of deferred tax benefits associated with the sale of Malaysia assets and sanction of a development in Block H Malaysia, larger U.S. tax benefits related to exploration losses in foreign areas where the Company has completed operations and exited the area, and lower overall pretax earnings. As to the Malaysia sale, no local income taxes were owed and a deferred tax benefit arose due to the purchaser assuming certain future tax payment obligations. The effective tax rate in 2014 was 18.2%, down from 39.7% in 2013. The Malaysian tax benefits upon sale of 20% interest, combined with higher U.S. tax benefits on foreign exploration areas led to an effective tax rate for the Company in 2014 below the 35.0% U.S. statutory tax rate.

2013 vs. 2012 – Net income in 2013 was $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 2012 and 2013 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.

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Sales and other operating revenues grew $704.1 million in 2013 compared to 2012. 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 2012. 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, in 2013, 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 later year. Lease operating expenses increased $173.7 million in 2013 due to higher overall hydrocarbon production levels and costs related to shutdown of the Azurite field in Republic of the Congo. Severance and ad valorem taxes increased $51.7 million in 2013 compared to 2012 mostly due to higher production and well counts in the Eagle Ford Shale. 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 United States. 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 2013 compared to 2012 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 2012 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 2013 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 and a higher average interest rate caused by a full year of interest applicable on notes payable issued in 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 2013. Income tax expense increased $23.0 million in 2013 due to higher earnings before taxes, but this was partially offset by higher U.S. 2013 income tax benefits for tax deductions on investments in foreign upstream operations for which the Company has exited. 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 rates 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.

Segment Results – In the following table, the Company's results of operations for the three years ended December 31, 2014, 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)	2014	2013	2012
Exploration and production – continuing operations			
United States	$ 387.1	435.4	168.0
Canada	156.5	180.8	208.1
Malaysia	896.2	786.4	894.2
Other	(250.0)	(373.8)	(365.3)
Total exploration and production – continuing operations	1,189.8	1,028.8	905.0
Corporate and other	(164.8)	(140.7)	(98.5)
Income from continuing operations	1,025.0	888.1	806.5
Income (loss) from discontinued operations	(119.4)	235.4	164.4
Net income	$ 905.6	1,123.5	970.9

Exploration and Production – Earnings from exploration and production (E&P) continuing operations were $1,189.8 million in 2014, $1,028.8 million in 2013 and $905.0 million in 2012. Income from exploration and production operations increased $161.0 million in 2014 compared to 2013 primarily due to an after-tax gain of $321.4 million on sale of 20% of the Company's interest in Malaysia in late 2014. Excluding this gain in Malaysia, E&P earnings declined $160.4 million in 2014, essentially due to lower margins realized on oil sales. The margin decline was attributable to lower average crude oil sales prices in the just completed year. Crude oil sales prices fell during 2014 in all areas of the Company's operations, and crude oil price realizations averaged $87.23 per barrel in the current year compared to $94.96 per barrel in 2013, a price drop of 8% year on year. Oil and gas extraction costs, including associated production taxes, were slightly lower on a per-unit basis, but increased overall by $210.8 million due to higher combined total oil and gas sales volumes of 8.5% during 2014. Compared to 2013, total sales volumes in 2014 for crude oil rose 6%, while natural gas liquids sales volumes rose 213% and natural gas sales volumes rose 5%. These 2014 increases in crude oil and gas liquids sales volumes were primarily associated with growth in operations in the Eagle Ford Shale, while natural gas volumes increased due to both Eagle Ford Shale drilling and start-up of the Dalmatian field in the Gulf of Mexico. Crude oil sales volumes offshore Sarawak Malaysia increased in 2014 due to a full year of production from new oil fields brought online in 2013. Crude oil sales volumes in 2014 offshore Block K Malaysia were less than the prior year due to lower production at the Kikeh field coupled with an underlift of sales volumes based on timing of the Company's cargo sales. Heavy oil sales volumes in Canada were lower in 2014 due to well decline in the Seal area. Also, more downtime for synthetic oil operations led to lower sales volumes in the just completed year. The final cargo sale in Republic of the Congo occurred in early 2013 and the field has been abandoned. The Company brought on new natural gas wells in the Tupper area of Western Canada in the second half of 2014, but these new gas volumes did not fully offset production decline at other gas wells in the area during the full year 2014. Lease operating expenses were $163.0 million lower in 2014 primarily due to no repeat of 2013 costs associated with the now abandoned Azurite field in Republic of the Congo. Excluding the costs in Republic of the Congo, lease operating expenses increased by $28.0 million in 2014, primarily due to higher oil and gas production levels in the Eagle Ford Shale area. Severance and ad valorem taxes increased $19.9 million in 2014 compared to the prior year due to continued growth in production volumes and well count in the Eagle Ford Shale. Depreciation expense for E&P operations increased $353.9 million in 2014 due to higher overall production levels and capital amortization rates above the Company's average for new production added in the Gulf of Mexico and offshore Malaysia. Accretion expense related to discounted asset retirement obligations increased $1.8 million as expense associated with new wells in the Gulf of Mexico and offshore Malaysia was only partially offset by the favorable effect of settling abandonment obligations in Republic of the Congo. Asset impairment expense of $51.3 million in 2014 was higher by $29.7 million; significantly weaker oil and gas prices at year-end 2014 led to writedown of a natural gas field in the Gulf of Mexico and writeoff of goodwill associated with an oil and gas company acquired in 2000 in

Western Canada. Exploration expense was $11.4 million higher in 2014 due to larger amortization costs associated with dropping remote undeveloped leases in the Eagle Ford Shale. Additionally, the Company had increased costs for exploratory wells drilled in an earlier year in the Gulf of Mexico and Malaysia that were expensed due to significantly lower natural gas prices and denial of a requested gas holding period extension, respectively. This was partially offset by lower seismic costs incurred in 2014 in Southeast Asia. Selling and general expenses for E&P operations increased $41.1 million in 2014 compared to the prior year due to higher overall staffing levels and less costs recovered from partners in Malaysia due to fewer development activities ongoing during the current year. Other expenses were $24.9 million in 2014 and primarily related to writedown in value of materials inventory associated with Malaysia operations. Income tax expense for E&P operations in 2014 was $370.6 million below 2013 levels due to lower pretax earnings, a benefit related to future tax liabilities assumed by the purchaser of 20% of assets in Malaysia, a benefit associated with sanction of a development plan in Block H Malaysia, and higher U.S. tax benefits in the current year associated with foreign operations that were exited.

E&P income in 2013 was $123.8 million above 2012 primarily due to higher crude oil sales volumes and lower impairment charges in the later 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 has exited. 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 2013 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 in 2013 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 compared to 2012. The average realized sales price for crude oil, condensate and natural 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 2013 at the Tupper and Tupper West areas in Western Canada. The Company voluntarily curtailed drilling activities in this area during 2012 and 2013 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 lease operating expenses were $173.7 million higher in 2013 primarily due to more oil and gas 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. Severance and ad valorem taxes were $51.7 million higher in 2013 than 2012 primarily due to production and well count growth in the Eagle Ford Shale. Depreciation, depletion and amortization increased $299.2 million in 2013 compared to 2012 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. Results in 2012 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 completed in 2014. Selling and general expenses in 2013 for E&P operations were $51.3 million above 2012 levels due to higher overall staffing levels and lower levels chargeable to Malaysian partners as allowed under the operating agreements. Income tax benefits associated with investments in foreign upstream operations where the Company has exited 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.

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-62 and F-63 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on pages 4 and 5 of the 2014 Annual Report (Exhibit 13 of this Form 10-K report).

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

(Millions of dollars)		2014	2013	2012
United States – Oil and gas liquids	$	2,062.1	1,724.7	976.1
– Natural gas		127.2	72.7	54.2
Canada – Conventional oil and gas liquids		453.3	507.2	411.7
– Synthetic oil		391.5	441.0	463.1
– Natural gas		201.3	198.1	209.8
Malaysia – Oil and gas liquids		1,680.2	1,875.0	1,946.0
– Natural gas		357.5	404.0	481.1
Republic of the Congo – oil		–	83.6	57.6
Total oil and gas revenues	$	5,273.1	5,306.3	4,599.6

The Company’s total crude oil and condensate production averaged 142,408 barrels per day in 2014, compared to 131,515 barrels per day in 2013 and 111,729 barrels per day in 2012. The 2014 crude oil production level was a Company record and 8% above 2013. Crude oil production in the United States totaled 59,900 barrels per day in 2014, up from 45,523 barrels per day in 2013. The 32% increase in U.S. crude oil production year over year was a U.S. record for the Company and was primarily related to increased volumes produced in the Eagle Ford Shale in South Texas. The Company’s Eagle Ford Shale drilling program utilized an average of almost eight drilling rigs during 2013 and 2014. U.S. production also benefited in 2014 from start-up of the Dalmatian field in the Gulf of Mexico. Heavy crude oil production in Western Canada fell from 9,123 barrels per day in 2013 to 7,411 barrels per day in 2014, with the reduction attributable to well performance decline in the Seal area. Crude oil volumes produced offshore Eastern Canada totaled 8,758 barrels per day in 2014, off from 9,099 barrels per day in the previous year as well decline at Hibernia was not fully offset by the benefit of less current-year downtime at Terra Nova. Synthetic crude oil production volume was 11,997 barrels per day in 2014 compared to 12,886 barrels per day in 2013 due to the current year experiencing greater levels of downtime for repairs. Crude oil production offshore Sarawak increased from 10,323 barrels per day in 2013 to 20,274 barrels per day in 2014; the Company brought several new fields online during 2013 which provided a full year of production in 2014. Block K in Malaysia had crude oil production of 34,021 barrels per day in 2014, down from 42,808 barrels per day in 2013. Both the Kakap main field and the Siakap field came on stream during 2014, but this partial year production did not fully offset lower production at the Kikeh field. The Kikeh field had lower production in 2014 due to a combination of an outage for hook-up of the Siakap field, a facility fire early in the year, and normal well decline. Prior to going off production in early 2013, the Azurite field produced 1,046 barrels of crude oil in the prior year. Additionally, discontinued fields in the U.K. that were all sold in early 2013 provided crude oil production of 648 barrels per day in the prior year.

Crude oil production in 2013 totaled 131,515 barrels per day, which was an 18% increase over 2012. United States crude oil production rose from 25,978 barrels per day in 2012 to 45,523 barrels per day in 2013 with the 75% volume increase virtually all related to drilling and other development operations in the Eagle Ford Shale area. Production of heavy oil in Western Canada was 9,123 barrels per day in 2013, up from 7,241 barrels per day in 2012, primarily due to volumes in 2013 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 2013 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 facility downtime for maintenance in 2013. Crude oil production in Malaysia increased from 51,950 barrels per day in 2012 to 53,131 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 field being operational for all of 2013 following a late 2012 start-up. The Kakap main field production system came onstream in October 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 2013, and U.K. oil production therefore declined during that year. All U.K. oil and gas production volumes have been reported as discontinued operations.

The Company produced natural gas liquids (NGL) of 9,239 barrels per day in 2014, up from 3,563 barrels per day in 2013, and 862 barrels per day in 2012. The higher NGL volumes of 5,676 barrels per day in the current year were mostly attributable to increases of 3,714 barrels per day in the Eagle Ford Shale and 1,227 barrels per day at the new Dalmatian field in the Gulf of Mexico.

Worldwide sales of natural gas were 446.0 million cubic feet (MMCF) per day in 2014, compared to 423.8 MMCF per day in 2013 and 490.1 MMCF per day in 2012. Significant development drilling in the Eagle Ford Shale and start-up of the Dalmatian field in the Gulf of Mexico drove up U.S. natural gas sales volumes from 53.2 MMCF per day in 2013 to 88.5 MMCF per day in 2014. Natural gas sales volumes in Canada fell from 175.4 MMCF per day in 2013 to 156.5 MMCF per day in 2014 as decline at existing wells in the Tupper area of British Columbia were not fully offset by gas volumes produced at new wells brought on line during the just completed year. At the Company's fields offshore Sarawak Malaysia, gas production increased from 164.7 MMCF per day in 2013 to 168.7 MMCF per day in 2014 due to higher customer demand in the later year. Natural gas sales volumes from Block K offshore Malaysia were 32.3 MMCF per day in 2014, up from 29.7 MMCF per day in 2013 due to higher demand from the third party receiving facility.

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 voluntarily curtailed drilling activities in this dry gas basin in 2012 and 2013 due to 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, with the reduction 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.

The Company's average worldwide realized sales price for crude oil and condensate from continuing operations was \$87.23 per barrel in 2014 compared to \$94.90 per barrel in 2013 and \$95.39 per barrel in 2012.

The average realized crude oil sales price for continuing operations was 8% lower in 2014 compared to the prior year. Although West Texas Intermediate (WTI) crude oil averaged 5% less in 2014, other indices on which the Company sells crude oil fell more compared to the prior year. Dated Brent and Kikeh oil each sold for 9% less in 2014, while Light Louisiana Sweet crude oil sold at 11% below 2013 levels. The average realized sales prices for U.S. crude oil and condensate amounted to \$90.79 per barrel in 2014, 11% lower than 2013. Heavy oil produced in

Canada brought $54.18 per barrel in 2014, a 16% increase from 2013, as a reduction in the discount for heavy oil in 2014 more than offset the impact of lower worldwide benchmark prices in the current year. The average sales price for crude oil produced offshore Eastern Canada declined 12% to $95.95 per barrel in 2014. The average realized sales price for the Company's synthetic crude oil was $89.51 per barrel in 2014 down 7% from the prior year. Crude oil sold in Malaysia averaged $85.85 per barrel in 2014, 9% lower than in 2013.

During 2013, the average realized crude oil sales price for continuing operations fell by 1% compared to 2012. Oil prices on various indices were mixed in 2013 compared to a year earlier. Although WTI 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 1% to $101.70 per barrel in 2013. Heavy oil price realizations in Canada increased 1% to $46.78 per barrel in 2013. Oil prices offshore Eastern Canada in 2013 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 $94.26 per barrel in 2013, which was a decline of 3% from 2012. Average crude oil sales prices in Republic of the Congo were $109.43 per barrel in 2013, a 2% increase from 2012.

The average sales price for natural gas liquids (NGL) was also lower in 2014 than 2013. These NGL prices are generally considered to be weak compared to the comparable heating value of crude oil, primarily due to an oversupply of NGL with the recent drilling growth in U.S. shale plays exceeding refinery and other demand for this product. NGL was sold in the U.S. for an average of $26.83 per barrel in 2014, down 11% from the average price of $30.31 per barrel in 2013. NGL produced in Malaysia in 2014 was sold for an average of $75.18 per barrel, 26% below the 2013 average of $101.40 per barrel.

North American natural gas prices were stronger in 2014 than 2013, essentially driven by higher gas energy demand due to an extremely cold winter season on the continent. The average posted price at Henry Hub in Louisiana was $4.34 per million British Thermal Units (MMBTU) in 2014 compared to $3.72 per MMBTU in 2013 and $2.94 per MMBTU in 2012. In 2014, U.S. natural gas was sold at an average of $3.98 per thousand cubic feet (MCF), a 4% increase compared to 2013. Natural gas sold in Canada averaged $3.60 per MCF in 2014, up 17% from 2013. Natural gas sold in 2014 from Sarawak Malaysia averaged $5.71 per MCF, down 14% from the prior year.

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 2013.

Based on 2014 sales volumes and deducting taxes at statutory rates, each $1.00 per barrel oil sales price fluctuation and $0.10 per MCF gas sales price fluctuation would have affected 2014 earnings from exploration and production continuing operations by $33.6 million and $10.9 million, respectively. The effect of these price fluctuations on consolidated net income cannot be measured precisely because operating results of the Company's U.K. refining and marketing discontinued operations could have been affected differently.

Production-related expenses for continuing exploration and production operations during the last three years are shown in the following table.

(Millions of dollars)		2014	2013	2012
Lease operating expense	$	1,089.9	1,252.9	1,079.2
Severance and ad valorem taxes		107.2	87.3	35.6
Depreciation, depletion and amortization		1,897.5	1,543.6	1,244.4
Total	$	3,094.6	2,883.8	2,359.2

Cost per equivalent barrel sold for these production-related expenses are shown by geographical area in the following table.

(Dollars per equivalent barrel)	2014	2013	2012
United States – Eagle Ford Shale			
Lease operating expense	$ 11.25	11.15	19.45
Severance and ad valorem taxes	4.64	5.39	4.68
Depreciation, depletion and amortization (DD&A) expense	27.87	30.48	32.75
United States – Gulf of Mexico and other			
Lease operating expense	11.73	17.28	16.19
Severance and ad valorem taxes	0.02	0.09	0.08
DD&A expense	27.47	21.32	20.36
Canada – Conventional operations			
Lease operating expense	10.37	10.50	8.80
Severance and ad valorem taxes	0.36	0.29	0.19
DD&A expense	17.00	18.58	15.64
Canada – Synthetic oil operations			
Lease operating expense	53.39	47.47	43.29
Severance and ad valorem taxes	1.16	1.04	1.01
DD&A expense	12.32	11.79	10.94
Malaysia			
Lease operating expense – Sarawak	7.91	9.43	10.43
– Block K	15.04	14.30	14.40
DD&A expense – Sarawak	20.30	14.01	14.86
– Block K	26.79	22.21	16.92
Total oil and gas operations			
Lease operating expense	13.31	16.66	15.41
Severance and ad valorem taxes	1.31	1.16	0.51
DD&A expense	23.16	20.53	17.77

Lease operating expenses totaled $1,089.9 million in 2014, compared to $1,252.9 million in 2013 and $1,079.2 million in 2012. Lease operating expense per equivalent barrel in the Eagle Ford Shale was essentially flat in 2014 and 2013, while cost per barrel in the Gulf of Mexico declined in 2014 primarily due to higher production related to start-up of the Dalmatian field and lower fixed charges for a third party processing facility at Thunder Hawk. Lease operating expense for conventional operations in Canada was down slightly in 2014 due mostly to a lower Canadian dollar exchange rate. Lease operating expense per barrel for synthetic oil operations rose in 2014 compared to the prior year due to a combination of lower net production and higher maintenance and power costs. Lease operating expense for Sarawak oil and gas operations declined in 2014 per barrel due to higher full-year 2014 volumes produced at oil fields which started up during 2013. Block K operations had higher lease operating expense per barrel in 2014 due to overall lower production, but with a benefit from start-up of the main Kakap field in the second half of the year.

Lease operating expense per equivalent barrel in the Eagle Ford Shale declined in 2013 compared to 2012 due to both higher production volumes and cost management activities. Gulf of Mexico lease operating expense was higher in 2013 than the prior year due to more costs at the Thunder Hawk field. The per-unit cost for Canadian conventional oil and gas operations was higher in 2013 compared to 2012, primarily caused by a larger 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. Higher lease operating 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. Lease operating cost per unit in Sarawak Malaysia was down in 2013 compared to 2012, with the reduction primarily associated with lower costs at the new oil fields started up in 2013. 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 did not repeat in 2014 and due to field shutdown in late 2013, the effect of Azurite production has been omitted from the total oil and gas operations costs per equivalent barrel sold in the table on the preceding page in 2013 and 2012 to provide a more meaningful comparison to 2014 operations.

Severance and ad valorem taxes totaled $107.2 million in 2014, $87.3 million in 2013 and $35.6 million in 2012. Severance and ad valorem taxes in the United States in 2014 rose overall in tandem with growth in production. On a per barrel equivalent basis, Eagle Ford Shale production taxes were less in 2014 than 2013 due to a lower mix of production value primarily caused by a larger increase in growth of lower value natural gas liquids in this area.

Depreciation, depletion and amortization expense for continuing exploration and production operations totaled $1,897.5 million in 2014, $1,543.6 million in 2013 and $1,244.4 million in 2012. The $353.9 million increase in 2014 compared to 2013 was attributable to added production in areas that carry a higher overall capital amortization cost in the current year, in particular at Eagle Ford Shale, Dalmatian, Kakap main field and Siakap. The rate per equivalent barrel in 2014 at Eagle Ford Shale declined due to the timing of reserves migrated to the proved category and cost improvements achieved on more recent drilling activities. The per barrel cost in the Gulf of Mexico increased in 2014 due to start-up of the Dalmatian field where costs early in the life of the field exceed the U.S. average due to the timing of migration of reserves to the proved category. Canada conventional cost per barrel declined in 2014 mostly due to a lower Canadian dollar exchange rate in the current year. Synthetic oil operations had a higher per barrel cost due to straight-line depreciation costs for certain processing facilities being expensed over fewer production barrels. Depreciation per barrel rose in 2014 for both Sarawak and Block K areas due to new field production carrying a higher capital amortization cost per unit compared to the more mature fields in these areas.

The $299.2 million increase for depreciation, depletion and amortization in 2013 compared to 2012 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. Depreciation rates per equivalent barrel in the Eagle Ford Shale were lower in 2013 due to efficiency gains in drilling activities as the field development progressed. Depreciation rates in the Gulf of Mexico in 2013 were above 2012 levels primarily due to a larger mix of production from higher costs fields. The depreciation rate per unit for conventional operations in Canada was higher in 2013 due to the costs for added reserves being above prior year average costs during recent years. Synthetic oil operations had a higher per barrel depreciation rate in 2013 due to lower production volumes, as certain facilities are depreciated on a straight-line basis at this operation. Depreciation expense per unit for Sarawak production declined in 2013 versus the prior year due to a lower unit rate on a mature field caused by positive additions to proved reserves. Block K depreciation per barrel also increased in 2013 compared to 2012 due to higher development costs at

Kikeh for new wells brought online.

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-62 and F-63 on this Form 10-K report. Expenses other than undeveloped lease amortization are included in the capital expenditures total for exploration and production activities.

(Million of dollars)		2014	2013	2012
Dry holes	$	270.0	262.9	181.9
Geological and geophysical		99.5	117.5	32.2
Other		69.7	54.9	37.0
		439.2	435.3	251.1
Undeveloped lease amortization		74.4	66.9	129.8
Total exploration expenses	$	513.6	502.2	380.9

Dry hole expense in 2014 was $7.1 million more than in 2013 primarily due to expensing prior-year wells in Malaysia and the Gulf of Mexico that had been previously suspended while development options were studied. The dry hole costs in Malaysia of $47.4 million for these wells were attributable to government denial of a request to extend a gas holding period for Block PM 311, while the previously suspended Gulf of Mexico dry hole for $18.8 million was caused by low year-end 2014 natural gas prices. The current year also included costs of $103.9 million for an unsuccessful well in Cameroon. These higher 2014 costs were partially offset by the costs of unsuccessful exploration drilling conducted in Australia in 2013. Geological and geophysical (G&G) expense was $18.0 million lower in 2014 due to less spending in the current year for seismic data covering exploration prospects in Southeast Asia. Other exploratory costs were up $14.8 million in 2014 due to higher exploration staff and office costs in Southeast Asia, a charge-off in the current year of shared drilling equipment improvement costs for a third-party rig that was released, and a penalty associated with an exploration well that was not drilled on a license in Indonesia. Undeveloped lease amortization increased $7.5 million primarily due to higher amortization related to remote unproved lease acreage released in the Eagle Ford Shale, but partially offset by no repeat in the current year of lease costs written off in 2013 in the Kurdistan region of Iraq.

Dry hole expense in 2013 was $81.0 million more than 2012 due to higher unsuccessful exploratory drilling costs in the later 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. 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.

Impairment expense in 2014 for E&P operations exceeded 2013 by $29.7 million. The current year charge included write-off of goodwill recorded in a business acquisition in Western Canada in 2000, and a writedown of one natural gas field in the Gulf of Mexico. Both charges in 2014 were required due to the weakness in oil and natural gas prices, which retreated severely in late 2014.

During 2013, E&P operations had lower impairment expense of $178.4 million when compared to 2012. 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.

The exploration and production business recorded expenses of $50.8 million in 2014, $49.0 million in 2013 and $38.4 million in 2012 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 $1.8 million increase in 2014 primarily related to development wells added in the Gulf of Mexico during the year. 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, along with higher estimated abandonment liabilities for synthetic oil operations in Canada and oil fields in Malaysia and Republic of the Congo.

The effective income tax rate for exploration and production continuing operations was 19.4% in 2014, 38.9% in 2013 and 40.1% in 2012. The effective tax rate in 2014 was well below the tax rates in 2013 and 2012 and the statutory U.S. tax rate of 35.0% due primarily to tax benefits in foreign areas during the current year. With the sale of 20% of the assets in Malaysia near year-end 2014, the purchaser assumed certain future Malaysian tax obligations, which essentially reduced the Company’s deferred tax liabilities by $176.6 million. Additionally, the Company recognized a $65.4 million tax benefit during 2014 for past exploratory expenses incurred in Block H, where proved reserves were added at year-end 2014 related to a new field development plan. Also, in 2014 the Company recognized U.S. income tax benefits of $95.9 million associated with investments in exploration operations in Cameroon, the Kurdistan region of Iraq, and one block in Australia, in areas where the Company is exiting. 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 tax rates in 2012 and 2013 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. Through 2014, no tax benefits have thus far been recognized for costs incurred for Blocks PM 311/312, offshore Peninsular Malaysia, and Block SK 314A, offshore Sabah, Malaysia.

At December 31, 2014, 98.7 million barrels of the Company’s U.S. crude oil proved reserves, 12.6 million barrels of U.S. NGL proved reserves and 80.7 billion cubic feet of U.S. natural gas proved reserves were undeveloped. Approximately 84% 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. The deepwaters of the Gulf of Mexico accounted for the remaining 16% of proved undeveloped reserves at December 31, 2014. In the Western Canadian Sedimentary Basin, undeveloped natural gas proved reserves totaled 375.4 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 proved undeveloped reserves of 10.6 million barrels are primarily at the Kikeh field, where undeveloped proved oil reserves are subject to further drilling before being moved to developed. Also in Malaysia, there were 436.5 billion cubic feet of undeveloped natural gas proved reserves at various offshore fields at year-end 2014. These undeveloped natural gas reserves in Malaysia are mainly associated with Block H, where a development project commenced following sanction in 2014. On a worldwide basis, the Company spent approximately $3.21 billion in 2014, $3.40 billion in 2013 and $3.30 billion in 2012 to develop proved reserves.

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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". On September 30, 2014, Murphy Oil sold its U.K. retail marketing business. The Company is attempting to sell its U.K. finished products terminal operations in 2015. The Company was unable to sell its Milford Haven, Wales, refinery and has decided to decommission and abandon the facility. 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 on page 40 of this Form 10-K report.

Corporate – The after-tax costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and unallocated corporate overhead were $164.8 million in 2014, $140.7 million in 2013 and $98.5 million in 2012.

The net cost of Corporate activities in 2014 exceeded 2013 by $24.1 million, primarily due to higher net interest expense and lower profits on foreign currency exchange, but somewhat offset by lower administrative expenses. Interest income was $3.8 million higher in 2014 than 2013 due to larger average invested cash balances in Canada and interest earned on Canadian prior-year tax installments. Net interest expense, after capitalization of finance-related costs to development projects, was higher by $43.9 million in 2014 compared to the prior year due to larger average borrowing levels in 2014 and lower amounts of interest capitalized to development projects. Administrative expenses associated with corporate activities were lower in 2014 by $56.3 million, primarily due to nonrecurring expenses incurred in 2013 related to consulting and staffing for the U.S. retail marketing operations that was spun-off to shareholders in August 2013. The after-tax effects of foreign currency exchange was a gain of $39.9 million in 2014, but $30.4 million lower than in 2013. These effects arise due to transactions denominated in currencies other than the respective operation's predominant functional currency. The foreign currency gain recognized in 2014 was mostly realized in Malaysia, where a significantly weaker Malaysian ringgit in the current year led to a benefit from lower income tax obligations payable in the local currency. The Malaysian operation's functional currency is the U.S. dollar. However, the foreign currency gain variance in 2014 compared to the prior year was primarily related to the U.K. as an unfavorable earnings effect from the British pound sterling exchange rate in 2014 followed a favorable effect in 2013. Income tax benefits in 2014 for corporate activities were $13.4 million less than the prior year.

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. 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 was $57.0 million higher in 2013 than 2012. This unfavorable variance was principally due to higher average debt levels in 2013 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 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. 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 2013.

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 operations 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 operations. On September 30, 2014, the Company sold the U.K. retail marketing operations, and at December 31, 2014, the Company held for sale its U.K. finished products terminal operations. Following an extensive marketing effort, the Company was unable to sell its Milford Haven, Wales, crude oil refinery on acceptable terms. The Company has decided to shutter the refinery portion of the operation and is in the process of decommissioning the facility at year-end 2014.

- 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 dates the asset were sold, plus the cumulative gain realized upon sale.

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

(Millions of dollars)		2014	2013	2012
U.S. refining and marketing	$	–	134.8	87.3
U.K. refining and marketing		(120.6)	(119.2)	52.2
U.K. exploration and production		1.2	219.8	24.9
Income (loss) from discontinued operations	$	(119.4)	235.4	164.4

The loss from U.K. refining and marketing (R&M) operations of $120.6 million in 2014 was similar to the loss in 2013. The Company sold the retail marketing fueling stations during 2014 with an associated gain of $101.7 million. Total proceeds from the sale of the retail marketing assets were $212.0 million. The Milford Haven, Wales refinery ceased processing crude oil in May 2014. This refining operation incurred an impairment charge of $269.2 million in 2014, along with losses from operations and costs related to employee severance and other abandonment activities, which were partially offset by inventory profits arising from the sale of most of the refinery's inventory. Certain costs to be paid in 2015 or beyond relate to future services and will be recognized over the applicable service period.

The U.S. 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 of $216.1 million in 2013 from sale of all properties, but operating profits were lower in 2013 than 2012 due to only a partial year of operations prior to the property sales in 2013 versus a full year of operations in 2012. Total cash proceeds from sale of these assets were $282.2 million.

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 $3.76 billion in 2014, $3.97 billion in 2013 and $4.19 billion in 2012. These amounts excluded capital expenditures of $12.3 million in 2014, $154.6 million in 2013 and $190.9 million in 2012 related to discontinued operations, which were associated with U.K. refining and marketing operations which are either sold or held for sale at the end of 2014, U.S. retail marketing operations spun-off in August 2013, and U.K. oil and gas assets sold in the first half of 2013. Capital expenditures included $372.9 million, $435.3 million and $251.1 million, respectively, in 2014, 2013 and 2012 for exploration costs that were expensed.

Capital expenditures for exploration and production continuing operations totaled $3.74 billion in 2014, $3.94 billion in 2013 and $4.19 billion in 2012.

E&P capital expenditures in 2014 included $92.9 million for U.S. lease acquisitions, $430.1 million for exploration activities, and $3.21 billion for oil and gas project developments. U.S. lease acquisitions included acreage extensions in the Eagle Ford Shale as well as new leases acquired in the Gulf of Mexico. Exploration activities included drilling wells in the Gulf of Mexico, Cameroon, Indonesia and Vietnam. Additionally, exploration activities included seismic acquisition in the Gulf of Mexico and other areas, primarily related to prospects in Southeast Asia and West Africa. Development capital expenditures in 2014 included $1.52 billion for the drilling and completion program in the Eagle Ford Shale; $373.7 million for Gulf of Mexico development activities; $286.0 million for development work in the Western Canadian Sedimentary Basin; $92.5 million for the Syncrude project; $64.5 million combined for Hibernia and Terra Nova; $562.9 million for development projects in deepwater Malaysia, including Kikeh, Kakap and Siakap; and $299.3 million for oil and natural gas projects offshore Sarawak Malaysia.

E&P capital expenditures in 2013 included $35.6 million for lease acquisitions, $493.5 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 the Gulf of Mexico, including Dalmatian, which started up in 2014; $156.7 million for synthetic oil operations; $140.4 million for heavy oil at Seal; $283.5 million for Kikeh; $136.7 million for Kakap-Gumusut; $214.6 million for Siakap North-Petai; $681.3 million for Sarawak oil fields; and $49.6 million for Hibernia and Terra Nova, offshore Newfoundland.

E&P capital expenditures in 2012 included $132.5 million for acquisition of undeveloped leases, which primarily included leases acquired in the Gulf of Mexico, the Eagle Ford Shale area of South Texas and in Northwest Alberta, Canada, $450.6 million for exploration activities, $3.29 billion for development projects and $311.5 million for acquisition of proved properties in Canada and the Gulf of Mexico. Exploration activities primarily included exploratory drilling in the United States, Southern Alberta in Canada, Block H in Malaysia, Republic of the Congo, the Kurdistan region of Iraq and Brunei. Other primary exploration activities were associated with geophysical data acquisitions in the U.S. and various foreign countries. Development expenditures included $1.11 billion in the Eagle Ford Shale; $157.3 million at the Tupper and Tupper West areas; $200.1 million for deepwater fields in the Gulf of Mexico; $627.8 million for Kikeh; $558.6 million for oil and natural gas development activities in SK Blocks 309/311; $107.0 million and $83.9 million for the Kakap-Gumusut and Siakap North-Petai developments, respectively, in Block K, Malaysia; $125.1 million for Syncrude; $222.4 million for Western Canada heavy oil projects; and $73.1 million for the Terra Nova and Hibernia oil fields.

Exploration and production capital expenditures are shown by major operating area on page F-61 of this Form 10-K report.

Capital expenditures for discontinued operations included $114.3 million in 2013 and $111.5 million in 2012 for U.S. retail marketing operations, which primarily included station construction and other improvements in each year. U.K. refining and marketing operations had capital expenditures during the three years ended December 31, 2014, 2013, and 2012 of $12.3 million, $32.2 million and $22.2 million, respectively. U.K. E&P operations had capital expenditure of $8.1 million in 2013 and $57.2 million in 2012.

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Cash Flows

Operating activities – Cash provided by operating activities of continuing operations was $3.05 billion in 2014, $3.21 billion in 2013 and $2.91 billion in 2012. Cash flows associated with formerly owned U.S. downstream and U.K. oil and gas production businesses, plus sold, held for sale or abandoned U.K. downstream businesses, have been classified as discontinued operations in the Company's consolidated financial statements. Cash flow provided by continuing operations was $162.1 million lower in 2014 than in 2013 due to generally weaker crude oil sales prices along with higher payments for interest and income taxes in 2014 compared to the prior year. Cash flow provided by continuing operations was $299.3 million higher in 2013 compared to 2012. The increase in 2013 was attributable to higher income from continuing operations, plus higher dry hole costs, higher depreciation expense and a favorable impact from changes in working capital other than cash compared to the prior year. Cash provided by operating activities was reduced by expenditures for abandonment of oil and gas properties totaling $36.8 million in 2014, $51.6 million in 2013 and $40.4 million in 2012. Operating cash flows were reduced by payments of income taxes of $573.8 million in 2014, $457.0 million in 2013 and $567.0 million in 2012. The total reductions of operating cash flows for interest paid during the three years ended December 31, 2014, 2013 and 2012 were $134.8 million, $113.0 million and $48.7 million, respectively.

Investing activities – Capital expenditures of the exploration and production business represent the most significant component of investing activities. Property additions and dry hole costs for continuing operations used cash of $3.68 billion in 2014, $3.59 billion in 2013 and $3.54 billion in 2012. Cash of $986.3 million, $923.5 million and $1.62 billion was spent in 2014, 2013 and 2012, respectively, to acquire Canadian government securities with maturities greater than 90 days at the time of purchase. Proceeds from maturities of Canadian government securities with maturities greater than 90 days at date of acquisition were $899.9 million in 2014, $664.3 million in 2013 and $2.04 billion in 2012. Proceeds from sales of assets generated cash of $1.47 billion in 2014 and primarily arose due to sale of 20% of the Company's oil and gas assets in Malaysia.

Financing activities – During 2014, the Company sold its U.K. retail marketing assets as well as 20% of its oil and gas assets in Malaysia. Following these sales, the Company repatriated cash from the U.K. and Malaysia of $250 million and $1.7 billion, respectively. Foreign tax credits were available to cover most of the U.S. income taxes associated with these repatriated funds.

During 2014, the Company borrowed $100.0 million under bank financing arrangements. Funds generated from the sale of assets in Malaysia and the U.K. which were repatriated for the U.S., tempered with the Company's net borrowings during the just completed year, as the majority of these sales proceeds were used to pay down long-term debt before year-end 2014. The Company paid $25.3 million related to a capital lease obligation for production equipment at the Kakap field in 2014. The Company paid $375.0 million in 2014, $500.0 million in 2013 and $250.0 million in 2012 to repurchase 6.37 million shares, 7.86 million shares and 3.87 million shares, respectively, of its Common stock. Through December 31, 2014, the Company had repurchased no shares under a $500.0 million share buyback program approved by the Board of Directors on August 6, 2014. Cash used for dividends to stockholders was $236.4 million in 2014, $235.1 million in 2013 and $714.4 million in 2012. The Company increased its normal dividend rate by 12% in 2014 as the annualized dividend was raised from $1.25 per share to $1.40 per share effective in the third quarter 2014. In December 2012, the Company paid a special dividend of $2.50 per share. At the date of the spin-off, Murphy USA Inc. paid Murphy Oil Corporation cash of $650.0 million, which the Company primarily used to partially repay outstanding debt. However, Murphy USA retained cash of $55.5 million at the time of the separation. During 2012, the Company sold $2.0 billion of long term notes. The proceeds of these notes were primarily used to repay $350.0 million of notes that matured in 2012, to repay other debt, to fund a special dividend totaling $486.1 million, to fund a $250.0 million repurchase of Common stock, and to fund a portion of the Company's development capital expenditures. Cash proceeds from stock option exercises and employee stock purchase plans amounted to $0.2 million in 2014, $3.4 million in 2013 and $12.3 million in 2012. In 2014, 2013 and 2012, cash of $6.8 million, $16.7 million and $3.3 million, respectively, was used to pay statutory withholding taxes on stock-based incentive awards that vested with a net-of-tax payout.

Discontinued operations – These activities required operating cash flow of $39.6 million in 2014, but provided operating cash flow of $427.8 million and $144.9 million in 2013 and 2012, respectively. The latest year included only the U.K. refining and marketing activities which had poor refining margins prior to shutdown of the plant at Milford Haven in May 2014. Both 2013 and 2012 included positive operating cash flow from the U.S. retail marketing operations that were spun off to shareholders on August 30, 2013. Additionally, 2012 included a full year of operating cash contributions from U.K. oil and gas operations that were all sold in the first half of 2013. In 2014, the sale of U.K. retail marketing assets generated cash of $212.0 million. In 2013, the sale of all U.K. oil and gas assets generated cash of $282.2 million. Cash utilized for other investing activities of discontinued operations totaled $12.5 million in 2014, $165.7 million in 2013 and $192.5 million in 2012 and these mostly related to cash payments for capital expenditures. At December 31, 2014, the Company's held for sale U.K. downstream business had cash of $200.5 million. This cash is classified within Current assets held for sale on the Consolidated Balance Sheet at year-end 2014, effectively removing this amount from the Company's reported cash balance. This cash balance was $100.8 million lower than the cash balance of $301.3 million classified as held for sale as of December 31, 2013.

Financial Condition

Year-end working capital (total current assets less total current liabilities) amounted to $131.3 million at

year-end 2014 and $284.6 million at year-end 2013. Cash and cash equivalents at the end of 2014 totaled $1.19 billion compared to $750.2 million at year-end 2013. As described in the following paragraph, a portion of this cash held at year-end 2014 was used to pay down $450.0 million of short-term debt in January 2015. In addition to the Company's cash position it held short-term investments in Canadian government treasury securities of $461.3 million at year-end 2014, up $86.5 million compared to 2013. These short-term investments increased in 2014 primarily due to free cash flow generated by the Company's Canadian subsidiary during the just completed year. These slightly longer-term Canadian investments were purchased in each year because of a tight supply of shorter-term securities available for purchase in Canada. These short-term Canadian government investments could quickly be converted to cash if a need for funds in Canada arise.

Long-term debt at year-end 2014 was $400.3 million lower than year-end 2013. The debt reduction in 2014 was achieved by using most of the proceeds from a 20% sale of oil and gas assets in Malaysia to repay debt. Prior to the Malaysia sale in December 2014, long-term debt had risen in 2014 due to a combination of capital expenditures, share buyback and cash dividends, which in total exceeded cash generated from operating activities. At December 31, 2014, long-term debt represented 22.8% of total capital employed. Also, at December 31, 2014, current maturities of long-term debt included $450.0 million of loans that were repaid on January 15, 2015 with proceeds from the sale of Malaysian assets. During 2013, long-term debt increased by $691.4 million compared to year-end 2012. Of this increase in 2013, $342.0 million related to a non-cash capital lease of production equipment at the Kakap-Gumusut field, offshore Malaysia. The remainder of the debt increase in 2013 was necessitated by a combination of capital expenditures, share buybacks and cash dividends, which in total exceeded cash generated from operating activities, sale of assets, and amounts paid to the Company by Murphy USA Inc. at the separation date. At December 31, 2013, long-term debt was 25.5% of total capital employed. Stockholders' equity was $8.57 billion at the end of 2014 compared to $8.60 billion at the end of 2013 and $8.94 billion at the end of 2012. Stockholders equity declined in 2014 primarily due to a total of $375.0 million of Common stock repurchases during the year coupled with a reduction in the balance of foreign currency translation due to a weakening of the Canadian dollar against the U.S. dollar during the year. Stockholders' equity declined in 2013 principally due to the spin-off of Murphy USA Inc. and Common stock repurchases during the year.

Other significant changes in Murphy's year-end 2014 balance sheet compared to 2013 included a $126.6 million decrease in accounts receivable, primarily caused by lower overall sales prices at year-end 2014 compared to 2013. Inventory values were $51.5 million less at year-end 2014 than in 2013 mostly due to 20% sale of Malaysian properties in December 2014 and lower materials inventory balance in the current year. Current assets held for sale amounted to $376.1 million at December 31, 2014 and $943.7 million at December 31, 2013. The year-end 2014 amount primarily included cash held by the U.K. downstream business plus amounts receivable for sales of finished products to customers and finished products inventory. Net property, plant and equipment decreased by $150.0 million in 2014 primarily due to the disposition of 20% of Malaysia oil and gas assets in December 2014. Goodwill decreased $40.3 million in 2014 due to an impairment of goodwill at year-end 2014 associated with low oil and gas prices. Deferred charges and other assets decreased $17.0 million in 2014 due to both writedown of shared deepwater rig upgrade costs due to exchanging the upgraded rig for alternate drilling equipment and amortization of issue costs of notes payable. Assets held for sale-noncurrent of $51.0 million at December 31, 2014 represented property and equipment of the U.K. downstream business still held for sale at year-end 2014, while the balance of $381.4 million at December 31, 2013 primarily related to property and equipment, deferred turnaround costs and other noncurrent assets of the U.K. downstream business that were either sold or abandoned and written off during 2014. Current maturities of long-term debt at year-end 2014 was $439.1 million higher than at the prior year-end due to a short-term debt obligation of $450.0 million in the current year, which was fully repaid in January 2015, but partially offset by lower current payment obligations for a capital lease covering production equipment at the Kakap-Gumusut field, offshore Malaysia. Accounts payable increased by $117.3 million at year-end 2014 compared to 2013 primarily caused by higher royalty liabilities due to a change in timing of payments for Eagle Ford Shale royalties, higher amounts owed for operating and capital expenses in the U.S. and Malaysia, and liabilities related to anticipated adjustments for Malaysia sale proceeds at year-end 2014. Income taxes payable was $163.9 million lower at year-end 2014 than at the end of 2013, primarily due to higher tax payments in Malaysia in 2014. Other taxes payable increased $18.5 million in 2014 primarily due to higher U.S. ad valorem and severance taxes owed. Current liabilities associated with assets held for sale of $151.5 million at December 31, 2014 decreased $487.6 million compared to the prior year-end primarily due to no liabilities for crude oil purchases in the current year at the now shutdown Milford Haven, Wales refinery. Noncurrent deferred income tax liabilities were $272.2 million lower at year-end 2014 mostly due to assumption of certain future tax obligations by the purchaser of 20% of the Company’s oil and gas assets in Malaysia in 2014. The non-current liability associated with future asset retirement obligations decreased by $11.0 million at year-end 2014 also mostly due to obligations assumed by the purchaser of Malaysian assets that more than offset liabilities for new wells drilled in 2014. Deferred credits and other liabilities were $102.0 million higher in 2014 compared to 2013 primarily due to increases in pension and postretirement liabilities based on a decrease in the discount rate and newly revised participant mortality assumptions. Non-current liabilities associated with assets held for sale at December 31, 2014 decreased by $87.2 million primarily due to lower balances of non-current deferred tax liabilities for the U.K. refining and marketing business held for sale or being abandoned. Total stockholders’ equity of the Company decreased by $22.3 million in 2014. A summary of transactions in stockholders’ equity accounts is presented in the Consolidated Statement of Stockholders’ Equity on page F-8 of this Form 10-K report.

Murphy had commitments for future capital projects of approximately $1.38 billion at December 31, 2014. These commitments included $416.9 million for field development and future work in Malaysia, $379.0 million for work in the Eagle Ford Shale, $279.4 million for costs to develop deepwater Gulf of Mexico fields, and $86.9 million, $79.0 million, $52.4 million and $43.8 million for future work commitments offshore Namibia, Equatorial Guinea, Vietnam and Australia, respectively.

The primary sources of the Company’s liquidity are internally generated funds, access to outside financing and working capital. The Company uses its internally generated funds to finance the major portion of its capital and other expenditures, but it also maintains lines of credit with banks and borrows as necessary to meet spending requirements. At December 31, 2014, the Company had access to a long-term committed credit facility in the amount of $2.0 billion. A total of $450.0 million was borrowed under the committed credit facility at year-end 2014, but this balance was fully repaid on January 15, 2015 leaving the full $2.0 billion available in 2015 for future needs. The most restrictive covenants under this committed credit facility limit the Company's long-term debt to capital ratio (as defined in the agreements) to 60%. The committed credit facility expires in June 2017. At December 31, 2014, the Company had uncommitted bank credit lines of approximately $435.0 million, but no borrowings were outstanding under these lines. The Company's ratio of long-term debt to total capital was

22.8% at year-end 2014. In October 2012, the Company filed a Form S-3 registration statement with the U.S. Securities and Exchange Commission which permits the offer and sale of debt and/or equity securities. The Company used this shelf registration and a former one to sell long-term notes totaling $2.0 billion in 2012. The current shelf registration will expire in October 2015. Current financing arrangements are set forth more fully in Note F to the consolidated financial statements. Based on the anticipated level of 2015 capital expenditures for the Company, coupled with the current low price environment for crude oil, the Company anticipates that it will need to borrow funds under its long-term credit facility during 2015. The Company's ratio of earnings to fixed charges was 7.9 to 1 in 2014, 9.5 to 1 in 2013 and 15.1 to 1 in 2012.

Cash and invested cash are maintained in several operating locations outside the United States. At December 31, 2014, cash, cash equivalents and cash temporarily invested in Canadian government securities with greater than 90 day maturities held outside the U.S. included $515 million in Canada and $206 million in Malaysia. In addition, approximately $200 million of cash was held in the U.K. and has been classified as part of Assets held for sale at year-end 2014. In certain cases, the Company could incur cash taxes or other costs should these cash balances be repatriated to the U.S. in future periods. This could occur due to withholding taxes and/or potential additional U.S. tax burden when less than the U.S. tax rate of 35% has been paid for cash taxes in foreign locations. A lower cash tax rate is often paid in the U.S. and foreign countries in the early years of operations when accelerated tax deductions exist to incent oil and gas investments; cash tax rates are generally higher in later years after accelerated tax deductions in early years are exhausted. Canada collects a 5% withholding tax on any cash repatriated to the U.S. See Note I of the consolidated financial statements for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the United States.

Environmental Matters

Murphy faces various environmental and safety risks that are inherent in exploring for, developing and producing hydrocarbons. To help manage these risks, the Company has established a robust health, safety and environment governance program comprised of a worldwide policy, guiding principles, annual goals and a management system, with appropriate oversight at the business unit, senior leadership and board levels. The Company strives to minimize these risks by continually improving its processes through design, operation and maintenance, and through emergency and oil spill response planning to address any credible and major risks it identifies through impact assessments.

Murphy and other companies in the oil and gas industry are subject to numerous international, national, state, provincial and local environmental and safety laws and regulations. These requirements affect virtually all operations of the Company and increase Murphy's overall cost of business, including its capital costs to construct, maintain and upgrade equipment and facilities, and operating costs for ongoing compliance. Murphy allocates a portion of its capital expenditure program to comply with existing and anticipated environmental laws and regulations.

The principal environmental laws and regulations to which Murphy is subject address such matters as the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials, the emission and discharge of such materials to the environment, greenhouse gas emissions, wildlife, habitat and water protection and the placement, operation and decommissioning of production equipment. These laws and regulations also generally require permits for existing operations, as well as the construction or development of new operations. Any violation of applicable environmental laws, regulations or permits can give rise to significant civil and criminal penalties, injunctions, construction bans and delays, and other sanctions.

These laws, regulations and permits have been subject to frequent change and tended to become more stringent over time. For example, governmental initiatives have been implemented or are under development to regulate or further investigate the environmental impacts of hydraulic fracturing. In particular, the U.S. government has commenced a study to determine the environmental and health impacts of hydraulic fracturing and announced that it will propose standards for the treatment or disposal of wastewater from certain gas production operations.

In addition, certain jurisdictions in which the Company operates have required, or are considering requiring, more stringent permitting, chemical disclosure, transparency, water usage, disposal and well construction requirements. Regulators are also becoming increasingly focused on air emissions from the oil and gas industry, including volatile organic compound and methane emissions. For example, Alberta has announced regulations that would require Murphy's Seal facilities to conserve solution gas associated with primary recovery of heavy oil. In the United States, the Environmental Protection Agency has implemented requirements to reduce sulfur dioxide, volatile organic compound and hazardous air pollutant air emissions from oil and gas operations, including standards for wells that are hydraulically fractured. Any current or future air emission or other environmental requirements applicable to Murphy's businesses could curtail its operations or otherwise result in operational delays, liabilities and increased costs.

Murphy also could be subject to strict liability for environmental contamination, including with respect to its current or former properties, operations and waste disposal sites, or those of its predecessors. Contamination has been identified at certain of such sites as a result of which the Company may be required to remove or remediate previously disposed wastes, clean up contaminated soil, surface water and groundwater, address spills and leaks from pipelines and production equipment, and perform remedial plugging operations. In addition to significant investigation and remediation costs, such matters can also give rise to third party claims for fines, personal injury and property or other environmental damage.

Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations, and such capital expenditures were approximately $105 million in 2014. This spending is projected to be approximately $50 million in 2015 with the reduction due to a scale back in expected overall capital project spending associated with low oil and gas prices.

Climate Change

Greenhouse gas emission regulation is becoming more stringent. Murphy is currently required to report greenhouse gas emissions from certain of its operations and, in British Columbia, is subject to a carbon tax on the purchase or use of virtually all carbon-based fuels. Under the U.S. Climate Action Plan, the Environmental Protection Agency is currently assessing how best to pursue methane emission reductions from the oil and gas sector, which process may result in further voluntary or mandated methane mitigation measures. Any limitation, or further regulation of greenhouse gases, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could restrict the Company's operations, curtail demand for hydrocarbons generally or impose increased costs, including to operate and maintain facilities, install pollution emission controls and administer and manage an emissions trading program.

Safety Matters

The Company is subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable foreign and state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in Murphy’s operations and that this information be provided to employees, state and local government authorities and citizens. The Company believes that its operations are in substantial compliance with applicable safety requirements, including general industry standards, record-keeping requirements and the monitoring of occupational exposure to regulated substances.

Other Matters

Impact of inflation – General inflation was moderate during the last three years in most countries where the Company operates; however, the Company’s revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas and allied industries than by changes in general inflation. Crude oil prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the near future. Prices for oil field goods and services are usually affected by the worldwide prices for crude oil.

Prior to the late 2014 oil price collapse, the cost for oil field goods and services had generally risen. As noted elsewhere, oil prices have been extremely volatile over the last several years, as oil prices were quite strong in recent years, before declining dramatically in the fourth quarter of 2014 and into early 2015 due to an oversupply of crude oil in the global marketplace. With the recent decline in oil prices, the demand for goods and services has been diminished, which would normally lead to downward pressure on the prices of these goods and services. Natural gas prices are also affected by supply and demand, which are often affected by the weather and by the fact that delivery of gas is generally restricted to specific geographic areas. North American natural gas prices have been weak due to an oversupply of natural gas in this market. The recent severe pullback in crude oil prices has led many oil companies, including Murphy, to seek price concessions from suppliers of oil field goods and services. Due to the recent severe decline in oil prices coupled with the overall volatility of oil and natural gas prices, it is not possible to predict the Company’s future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements – In August 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) requiring, when applicable, disclosures regarding uncertainties about an entity’s ability to continue as a going concern. During the preparation of quarterly and annual financial statements, management should evaluate whether conditions or events exist that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the date the financial statements are issued. If this evaluation indicates that it is probable that an entity will be unable to meet its obligations when they become due within one year of the financial statement issuance date, management must evaluate whether its mitigation plans will alleviate the substantial doubt of continuing as a going concern. If substantial doubt exists, regardless of whether the mitigation plan alleviates the concern, additional disclosures are required in the financial statements addressing the conditions or events that raise substantial doubt, management’s evaluation of the significance of those conditions or events, and management’s mitigation plans. This new guidance will become effective for the Company for all reporting periods beginning in 2016. Early application is permitted. Company management currently does not expect that this new guidance will have a significant effect on its consolidated financial statements when adopted.

In May 2014, the FASB issued an ASU addressing recognition of revenue from contracts with customers. When adopted, this guidance will supersede current revenue recognition rules currently followed by the Company. The core principle of the new ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The ASU provides five steps for an entity to apply in recognizing revenue, including: (1) identify the customer contract; (2) identify the contractual performance obligations; (3) determine the transaction price; (4) allocate the transaction price to the contractual performance obligations; and (5) recognize revenue when the performance obligation is satisfied. The new ASU also requires additional disclosures regarding significant contracts with customers. The new ASU will be effective for the Company on January 1, 2017, and early adoption is not permitted. For transition purposes, the new ASU permits either (a) a retrospective application to all years presented, or (b) an alternative transition method whereby the new guidance is only applied to contracts not completed at the date of initial application. The vast majority of the Company’s revenue is recognized when oil and natural gas produced by the Company is delivered and legal ownership of these products has transferred to the purchaser. Based on the Company’s present understanding, the accounting for oil and gas sales revenue is not expected to be significantly altered by the new ASU. The Company has not yet selected which transition method it will use.

In April 2014, the FASB issued an ASU that will change the requirements for reporting discontinued operations after its adoption. Under the new guidance, only disposals of components of an entity that represent a strategic shift that has or will have a major effect on an entity’s operations and financial results will be reported as discontinued operations in the financial statements. Under prior guidance, a component of an entity that is a reportable segment, an operating segment, a reporting unit, a subsidiary, or an asset group that has been or will be eliminated from ongoing operations and for which the Company will not have any significant continuing involvement with the component after the disposal was generally reported as discontinued operations. The FASB anticipates that fewer component disposals will be reported as discontinued operations under the new guidance. The new guidance also requires expanded disclosures about discontinued operations. The new guidance will be effective for the Company beginning in 2015. The new guidance is not to be applied to a component that is classified as held for sale before the effective date of the guidance.

The United States Congress passed the Dodd-Frank Act (the Act) in 2010. As mandated by the Act, the U.S. Securities and Exchange Commission (SEC) issued rules regarding annual disclosures for purchases of "conflict minerals" and payments made to the U.S. Federal and all foreign governments by extractive industries, including oil and gas companies. "Conflict minerals" are defined as tin, tantalum, tungsten and gold which originate from the Democratic Republic of Congo or adjoining countries. For companies to whom the rule applies, an annual report for conflict minerals must be filed for each calendar year. Based on its assessment, the Company has determined that the rule does not currently apply to it and, therefore, it is not required to file an annual "conflict minerals" report.

On July 2, 2013, the United States District Court for the District of Columbia vacated the SEC's rules regarding reporting of payments made to the U.S. Federal and foreign governments. The D.C. Court found that the SEC misread the Act to mandate public disclosure of reports and that the denial of exemptions in the case of countries that prohibit public disclosures was improper. The Court remanded the matter to the SEC, which has indicated that it will restart the rulemaking process. The Company cannot predict how the SEC will alter its rules based on the Court's findings.

Significant accounting policies – In preparing the Company's consolidated financial statements in accordance with U.S. generally accepted accounting principles, management must make a number of estimates and assumptions related to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Application of certain of the Company's accounting policies requires significant estimates. The most significant of these accounting policies and estimates are described below.

· Oil and gas proved reserves – Oil and gas proved reserves are defined by the SEC as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether a deterministic method or probabilistic method is used for the estimation. Proved developed reserves of oil and gas can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Although the Company's engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. SEC rules require the Company to use an unweighted average of the oil and gas prices in effect at the beginning of each month of the year for determining quantities of proved reserves. These historical prices often do not approximate the average price that the Company expects to receive for its oil and natural gas production in the future. The Company often uses significantly different oil and natural gas price and reserve assumptions when making its own internal economic property evaluations. Estimated reserves are subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserves quantities. Reserves revisions inherently lead to adjustments of the Company's depreciation rates and the timing of settlement of asset retirement obligations. Downward reserves revisions can also lead to significant impairment expense. The Company cannot predict the type of oil and gas reserves revisions that will be required in future periods. The Company's proved reserves of crude oil, natural gas liquids and natural gas are presented on pages F-54 to F-60 of this Form 10-K report. Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data,

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and commercially available technologies, to establish 'reasonable certainty' of economic producibility. As defined by the SEC, reasonable certainty of proved reserves describes a high-degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses familiar industry-accepted methods for subsurface evaluations, including performance, volumetric, and analogue based studies. Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field-tested and have demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy's proved reserves estimates, and was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas, and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data, and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

See further discussion of proved reserves and changes in proved reserves during the three years ended December 31, 2014 beginning on pages 8 and F-54 of this Form 10-K report.

· Successful efforts accounting – The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on net income. Successful exploration drilling costs and all development capital expenditures are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by the Company's engineers. In some cases, a determination of whether a drilled well has found proved reserves cannot be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is, in turn, usually dependent on whether additional exploratory wells find a sufficient quantity of additional reserves. Under current accounting rules, the Company holds well costs in Property, Plant and Equipment in the Consolidated Balance Sheet when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Based on the time required to complete further exploration and appraisal drilling in areas where hydrocarbons have been found but proved reserves have not been booked, dry hole expense may be recorded one or more years after the original drilling costs are incurred. In 2014, the costs associated with four wells offshore Block PM 311 in Malaysia, which were drilled in 2004 and 2005, were written off due to denial of the Company's request to the Malaysian government for an extension to the gas holding period. Additionally, the cost of one well in the Gulf of Mexico, which was drilled in 2008, was written off because low-expected futures prices for natural gas at year-end 2014 rendered development opportunities for the field to be uneconomic. In 2013, two wells offshore Sarawak drilled in 2005 and 2006 were expensed when the Company decided not to move forward with development plans for this area. In 2012, a well in the MPN block offshore Republic of the Congo was expensed. This well had been drilled in late 2010 and was held until another well nearby could be drilled; the nearby well was unsuccessfully drilled in 2012. Also in 2012, two wells drilled offshore Sarawak in 2008 were expensed following a decision to halt development plans for these wells. Additionally in 2012, a well drilled in the Gulf of Mexico in 2010 was expensed following the owners' decision not to develop the well.

- Impairment of long-lived assets – The Company continually monitors its long-lived assets recorded in Property, Plant and Equipment and Goodwill in the Consolidated Balance Sheet to make sure that they are fairly presented. The Company must evaluate its properties for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable from future cash flows. Goodwill is evaluated for impairment at least annually. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, future capital and abandonment costs, and future inflation levels. The need to test a long-lived asset for impairment can be based on several factors, including but not limited to a significant reduction in sales prices for oil and/or natural gas, unfavorable revisions of oil or natural gas reserves, or other changes to contracts, environmental regulations or tax laws. All of these same factors must be considered when evaluating a property's carrying value for possible impairment. In making its impairment assessments involving exploration and production property and equipment, the Company must make a number of projections involving future oil and natural gas sales prices, future production volumes, and future capital and operating costs. Due to the volatility of world oil and gas markets, the actual sales prices for oil and natural gas have often been quite different from the Company's projections. Estimates of future oil and gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available. The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events, which include projections of future sales prices, future capital expenditures and future operating expenses. Future marketing or operating decisions, such as closing or selling certain assets, and future regulatory or tax changes could also impact the Company's conclusion about potential asset impairment.

The Company recorded impairment expense of $14.3 million in 2014 for one producing gas field in the Gulf of Mexico due to low year-end natural gas futures prices that would not permit full recovery of the investment in the field. Additionally, in 2014 the Company recorded an impairment charge of $37.0 million to write-off the remaining goodwill originally recorded with a business acquired in Western Canada in 2000. Low oil and gas prices at year-end 2014 led to the conclusion that this goodwill was no longer recoverable. The Company recorded writedowns of $269.2 million in 2014 and $73.0 million in 2013 for discontinued U.K. refining and marketing operations based on a fair value assessment of these assets being abandoned and/or held for sale at year-ends 2014 and 2013. Murphy recorded impairment expense of $21.6 million in 2013 related to the sale of Kainai properties in Western Canada at less than carrying value. The Company recorded impairment expense in 2012 of $200.0 million for the Azurite field, offshore Republic of the Congo, and $61.0 million in discontinued operations for the Hereford, Texas ethanol production facility. The Congo impairment was necessitated by removal of all proved oil reserves at Azurite following an unsuccessful redrill of a well; this result led to uneconomic future oil production operations for the field. The Hereford ethanol plant impairment was based on an expectation of continued weak future ethanol margins at the production facility owned by the Company's U.S. downstream subsidiary that was spunoff in 2013. The Hereford impairment was determined using available years of futures prices for corn and ethanol, plus a terminal value based on a reasonable multiple of the final year's cash flow.

Based on an evaluation of expected future cash flows from properties at year-end 2014, the Company did not have any other significant properties with carrying values that were impaired at that date. The expected future sales prices for crude oil and natural gas used in the evaluation were based on quoted future prices for the respective production periods. These quoted prices are based on market expectations for future hydrocarbon prices, which can often be significantly higher or lower in future periods compared to current spot prices. If quoted prices for future years had been weaker, the lower level of projected cash flows for properties could have led to significant impairment charges being recorded for certain properties in 2014. In addition, one or a combination of other factors such as lower future oil and/or natural gas prices, lower future production volumes, higher future costs, or the actions of government authorities could lead to impairment expenses in future periods. Based on these unknown future factors as described herein, the Company cannot predict the amount or timing of impairment expenses that may be recorded in the future.

· Income taxes – The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of its annual accounting period; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; and (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company. The Company has deferred tax assets mostly relating to basis differences for property, equipment and inventories, and liabilities for dismantlements and retirement benefit plan obligations. The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization. A valuation allowance has been recognized for deferred tax assets related to basis differences for Blocks PM 311/312 and SK 314A in Malaysia, for exploration licenses in certain areas, the largest of which are Australia, Indonesia and Brunei, and for certain basis differences in the U.K. due to management's belief that these assets cannot be deemed to be realizable with any degree of confidence at this time. In 2014, the Company recognized U.S. income tax benefits of $95.9 million related to tax deductions associated with investments in upstream operations in Cameroon, Kurdistan and Australia where the Company is exiting operations, as well as a Malaysian tax benefit of $65.4 million related to recognition of the expected future realization of tax deductions for prior-year Block H exploration expenses following sanction of the development plan for this field during 2014. In 2013, the Company recognized U.S. income tax benefits of $133.5 million related to tax deductions associated with investments in upstream operations in Republic of the Congo and Kurdistan, where the Company is exiting operations. During 2012, the Company recognized U.S. tax benefits related to upstream activities in Republic of the Congo and Suriname that totaled $108.1 million. These 2012 U.S. benefits arose due to tax deductions for worthless stock investments in these countries. The Company occasionally is challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in its various income tax returns. Although the Company believes that it has adequate liabilities recorded for matters not resolved with various taxing authorities, gains or losses could occur in future years from changes in estimates or resolution of outstanding matters.

· Accounting for retirement and postretirement benefit plans – Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most full-time employees. Effective with the spin-off of the Company's former U.S. retail marketing operation (MUSA) on August 30, 2013, significant modifications were made to the U.S. defined benefit pension plan. Certain employees' benefits under the U.S. plan were frozen at that time. No further benefit service will accrue for the affected employees, however, the plan will recognize future compensation increases after the spin-off. In addition, all previously unvested benefits became fully vested at the spin-off date. For those affected active employees of the Company, additional U.S. retirement plan benefits will accrue in future periods under a cash balance formula. Upon the spin-off of MUSA, the Company retained all vested pension defined benefit and other postretirement benefit obligations associated with current and former employees of this business. No additional benefit will accrue for employees of MUSA under the Company's retirement plan after the separation date. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is determined by management based

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on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs.

Based on bond yields at December 31, 2014, the Company has used a discount rate of 4.12% at year-end 2014 for the primary U.S. plans. This discount rate is 0.79% lower than a year earlier, which increased the Company's recorded liabilities for retirement plans compared to a year ago. Although the Company presently assumes a return on plan assets of 6.50% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The smoothing effect of current accounting regulations tends to buffer the current year's retirement plan expenses from wide swings in liabilities and asset valuations. The Company's retirement and postretirement plan expenses in 2015 are expected be higher than 2014 due to larger costs associated with previously unrecognized actuarial losses at year-end 2014. However, cash contributions are anticipated to be slightly higher in 2015 particularly associated with its domestic retirement plan. In 2014, the Company paid $47.3 million into various retirement plans and $3.7 million into postretirement plans. In 2015, the Company is expecting to fund payments of approximately $58.8 million into various retirement plans and $5.5 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected. Although Congress passed the Moving Ahead for Progress in the 21st Century Act, which permits certain companies to reduce retirement plan contributions in the near term, this Act does not reduce the Company's overall funding requirements in the long-term. As described above, the Company's retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2015 annual retirement and postretirement expenses by $5.4 million and $0.8 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2015 retirement expense by $2.9 million.

· Legal, environmental and other contingent matters – A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and other contingent matters. In addition, the Company often must estimate the amount of such losses. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company's management closely monitors known and potential legal, environmental and other contingent matters, and makes its best estimate of the amount of losses and when they should be recorded based on information available to the Company.

Contractual obligations and guarantees – The Company is obligated to make future cash payments under borrowing arrangements, operating leases, purchase obligations primarily associated with existing capital expenditure commitments, and other long-term liabilities. In addition, the Company expects to extend certain operating leases beyond the minimum contractual period. Total payments due after 2014 under such contractual obligations and arrangements are shown below.

	Amount of Obligations				
(Millions of dollars)	Total	2015	2016-2017	2018-2019	After 2019
Debt including current maturities	$ 3,001.6	465.4	582.4	36.2	1,917.6
Operating and other leases	421.6	108.7	123.3	82.7	106.9
Capital expenditures, drilling rigs and other	2,245.9	1,612.0	532.7	54.5	46.7
Other long-term liabilities, including debt interest	2,377.6	196.9	246.6	299.0	1,635.1
Total	$ 8,046.7	2,383.0	1,485.0	472.4	3,706.3

The Company has entered into agreements to lease production facilities for various producing oil fields. In addition, the Company has other arrangements that call for future payments as described in the following section. The Company's share of the contractual obligations under these leases and other arrangements has been included in the table above.

In 2013, the Company entered into a 25-year lease for a semi-floating production system at the Kakap field offshore Sabah, Malaysia. The Company has included the required lease obligations for this production system in the contractual obligation table above.

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide letters of credit that may be drawn upon if the Company fails to perform under those contracts. Total outstanding letters of credit were $116.5 million as of December 31, 2014, and all except $50.4 million of these letters of credit expire in 2015.

Material off-balance sheet arrangements – The Company occasionally utilizes off-balance sheet arrangements for operational or funding purposes. The most significant of these arrangements at year-end 2014 included operating leases of floating, production, storage and offloading vessels (FPSO) for the Kikeh and Azurite oil fields, an operating lease for a production facility at the West Patricia field, drilling contracts for onshore and offshore rigs in various countries, and oil and/or natural gas transportation contracts in the U.S. and Western Canada. The leases call for future monthly net lease payments through 2016 at West Patricia and Azurite and through 2023 at Kikeh. The U.S. and Western Canada transportation contracts require minimum monthly payments through 2023. Future required minimum annual payments under these arrangements are included in the contractual obligation table above.

Outlook

Prices for the Company’s primary products are often quite volatile. The price for crude oil is primarily affected by the levels of supply and demand for energy. Anticipated future variances between the predicted demand for crude oil and the projected available supply can lead to significant movement in the price of crude oil. In January 2015, West Texas Intermediate crude oil traded in a band between about $44.50 and $52.70 per barrel and averaged about $47.30 for the full month. NYMEX natural gas traded in a band of $2.70 to $3.20 per MMBTU, with an average of $3.00 during this same time. Both these oil and natural gas prices are well below the average prices achieved in 2014. The Company continually monitors the prices for its main products and often alters its operations and spending based on these prices.

The Company’s capital expenditure budget for 2015 was prepared during the fall of 2014 but has been reevaluated based on much weaker oil prices experienced in late 2014 and early 2015. Based on this reevaluation, capital expenditures in 2015 are expected to be well below 2014 levels, at a total of approximately $2.3 billion. Geographically, the current estimate of E&P capital in 2015 is spread approximately as follows: 65% for the United States, 19% for Malaysia, 11% for Canada and 5% for all other areas. Spending in the U.S. is primarily associated with development programs in the Eagle Ford Shale area of South Texas and for two deepwater projects in the Gulf of Mexico. In Malaysia, the majority of the spending is for continued development of the Kikeh, Kakap-Gumusut and Siakap North-Petai fields in Block K and oil development projects offshore Sarawak in Blocks SK 309/311. Canadian spending is primarily associated with natural gas development operations in Western Canada, plus development operations at Syncrude and East Coast offshore areas. Capital and other expenditures will be routinely reviewed during 2015 and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during the year. Capital expenditures may also be affected by asset purchases or sales, which often are not anticipated at the time a budget is prepared.

The Company will primarily fund its capital program in 2015 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company completed the sale of an additional 10% interest in Malaysia in January 2015. If needed for funding, the proceeds from this sale could be repatriated to the U.S., but certain U.S. tax obligations may arise if these funds are repatriated. The Company's 2015 projections call for borrowings of long-term debt during the year to fund a portion of the capital program. If oil and/or natural gas prices weaken further, actual cash flow generated from operations could be reduced such that higher than anticipated borrowings might be required during the year to maintain funding of the Company's ongoing development projects.

The Company currently expects production in 2015 to average between 195,000 and 207,000 barrels of oil equivalent per day. This level of production is significantly lower than 2014 due to a combined sale of 30% of Malaysian oil and gas assets in late 2014 and early 2015. If the sale in Malaysia had occurred on January 1, 2014, total production volumes for the just completed year would have averaged about 199,000 barrels of oil equivalent per day. A key assumption in projecting the level of 2015 Company production is the anticipated well decline rate following a period of reduced drilling activity in the Eagle Ford Shale area of South Texas, where a major drilling and completion operation has been scaled back due to weak oil prices. Another key factor in meeting 2015 production targets is the rate of decline of natural gas wells at the Tupper and Tupper West areas in Western Canada. Other keys to meeting the anticipated 2015 production levels include achieving expected full field production levels at the Kakap field, as well as continued reliability of production at significant operations such as Kikeh, Syncrude, Hibernia and Terra Nova, and the continued customer demand for natural gas from the Company's offshore Malaysia fields.

The Company has entered into forward delivery contracts to manage risk associated with certain Canadian natural gas sales prices as follows:

Commodity	Location	Dates	Average Volumes per Day	Average Prices
Canadian Natural Gas	TCPL-NOVA System	Jan. – Dec. 2015	65 mmcf/d	C$4.13 per mcf
		Jan. – Dec. 2016	9 mmcf/d	C$4.13 per mcf

In the low commodity price environment in early 2015, the Company is attempting to gain price concessions from many of its vendors that supply oil field goods and services. Certain costs are expected to retreat at the current level of oil and gas prices. It is unclear how successful the Company will be with achieving a meaningful reduction in the cost of oil field goods and services.

Following the 2013 separation of the U.S. downstream subsidiary from Murphy Oil Corporation, and the 2014 sale of the U.K. retail marketing business and shut down of the Milford Haven refinery, the Company is fundamentally different. The Company is now essentially a fully independent oil and gas company. The reduction in revenue, coupled with the loss of downstream earnings and a change in overall diversification could impact the Company's credit rating, and could, although not expected to, impact its ability to repay long-term debt obligations when they come due.

Forward-Looking Statements

This Form 10-K contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management's current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in these forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of Murphy's exploration programs, the Company's ability to maintain production rates and replace reserves, customer demand for Murphy's products, adverse foreign exchange movements, political and regulatory instability, adverse developments in the U.S. or global capital markets, credit markets or economies generally, and uncontrollable natural hazards. For further discussion of risk factors, see Item 1A. Risk Factors, which begins on page 14 of this Annual Report on Form 10-K. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to market risks associated with interest rates, prices of crude oil, natural gas and petroleum products, and foreign currency exchange rates. Murphy uses derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

As described in Note L, there were short-term derivative foreign exchange contracts in place at December 31, 2014 to hedge the value of U.S. dollar based receivables against the Canadian dollar. A 10% strengthening of the U.S. dollar against the Canadian dollar would have increased the recorded net liability associated with these contracts by approximately $1.9 million, while a 10% weakening of the U.S. dollar would have reduced the recorded net liability by approximately $2.3 million. Changes in the fair value of these derivative contracts generally offset the financial statement impact of an equivalent volume of foreign currency exposures associated with other assets and/or liabilities.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-66, which follow page 62 of this

Form 10-K report.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

Item 9A. CONTROLS AND PROCEDURES

Under the direction of its principal executive officer and principal financial officer, controls and procedures have been established by Murphy to ensure that material information relating to the Company and its consolidated subsidiaries is made known to the officers who certify the Company's financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, with the participation of the Company's management, as of December 31, 2014, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Murphy's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014. Management's report is included on page F-1 of this Form 10-K report. KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2014 and their report is included on page F-3 of this Form 10-K report.

There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2014 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on pages 20 and 21 of this

Form 10-K report. Other information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2015 under the captions "Election of Directors" and "Committees."

Murphy Oil has adopted a Code of Ethical Conduct for Executive Management, which can be found under the Corporate Governance and Responsibility tab at www.murphyoilcorp.com. Stockholders may also obtain free of charge a copy of the Code of Ethical Conduct for Executive Management by writing to the Company's Secretary at P.O. Box 7000, El Dorado, AR 71731-7000. Any future amendments to or waivers of the Company's Code of Ethical Conduct for Executive Management will be posted on the Company's Web site.

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2015 under the captions "Compensation Discussion and Analysis" and "Compensation of Directors" and in various compensation schedules.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2015 under the captions "Security Ownership of Certain Beneficial Owners," "Security Ownership of Management," and "Equity Compensation Plan Information."

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to Murphy’s definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2015 under the caption “Election of Directors.”

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by this item is incorporated by reference to Murphy’s definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2015 under the caption “Audit Committee Report.”

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements – The consolidated financial statements of Murphy Oil Corporation and consolidated subsidiaries are located or begin on the pages of this Form 10-K report as indicated below.

2. Financial Statement Schedules

All other financial statement schedules are omitted because either they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

3. Exhibits – The following is an index of exhibits that are hereby filed as indicated by asterisk (*), that are considered furnished rather than filed, or that are incorporated by reference. Exhibits other than those listed have been omitted since they either are not required or are not applicable.

Exhibit No.		Incorporated by Reference to
2.1	Purchase and Sale Contract for Malaysia assets	Exhibit 2.1 of Murphy's Form 10-Q report filed November 5, 2014
3.1	Certificate of Incorporation of Murphy Oil Corporation as amended, effective May 11, 2005	Exhibit 3.1 of Murphy’s Form 10-K report filed February 28, 2011
3.2	By-Laws of Murphy Oil Corporation as amended effective February 9, 2015	Exhibit 3.1 of Murphy’s Form 8-K report filed February 10, 2015

Exhibit No.		Incorporated by Reference to
4.1	Form of Indenture and Form of Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee	Exhibit 4.2 of Murphy’s Form 10-K report for the year ended December 31, 2009
4.2	Form of Indenture and First Supplemental Indenture between Murphy Oil Corporation and U.S. Bank National Association, as Trustee	Exhibits 4.1 and 4.2 of Murphy’s Form 8-K report filed May 18, 2012
4.3	Second Supplemental Indenture between Murphy Oil Corporation and U.S. Bank National Association, as Trustee	Exhibit 4.1 of Murphy’s Form 8-K report filed November 30, 2012
4.4	5-Year Revolving Credit Agreement dated June 14, 2011	Exhibit 4.1 of Murphy's Form 10-Q report filed August 5, 2014
4.5	Commitment Increase and Maturity Extension Agreement dated May 23, 2013	Exhibit 4.2 of Murphy's Form 10-Q report filed August 5, 2014
10.1	2007 Long-Term Incentive Plan	Exhibit 10.1 of Murphy’s Form 8-K report filed April 24, 2007
10.2	2012 Long-Term Incentive Plan	Exhibit A of Murphy’s definitive Proxy Statement (Definitive 14A) dated March 29, 2012
10.3	Employee Stock Purchase Plan as amended May 9, 2007	Exhibit 10.3 of Murphy’s Form 10-K report for the year ended December 31, 2012
10.4	2008 Stock Plan for Non-Employee Directors, as approved by shareholders on May 14, 2008	Form S-8 report filed February 5, 2009
10.5	2013 Stock Plan for Non-Employee Directors	Exhibit A of Murphy’s definitive Proxy Statement (Definitive 14A) dated March 22, 2013
10.6	Letter Agreement dated as of June 20, 2012, between the Company and David M. Wood	Exhibit 10.1 of Murphy’s Form 8-K report filed June 21, 2012
10.7	Tax Matters Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.1 of Murphy’s Form 8-K report filed September 5, 2013

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Exhibit No.		Incorporated by Reference to
10.8	Transition Services Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.2 of Murphy’s Form 8-K report filed September 5, 2013
10.9	Employee Matters Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.3 of Murphy’s Form 8-K report filed September 5, 2013
10.10	Trademark License Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.4 of Murphy’s Form 8-K report filed September 5, 2013
*12	Computation of Ratio of Earnings to Fixed Charges	
*13	2014 Annual Report to Security Holders	
*21	Subsidiaries of the Registrant	
*23	Consent of Independent Registered Public Accounting Firm	
*31.1	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*31.2	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*32	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
99.1	Form of employee stock option	Exhibit 99.1 of Murphy's Form 10-K report for the year ended December 31, 2013
*99.2	Form of performance-based employee restricted stock unit grant agreement	
99.3	Form of employee time-based restricted stock unit grant agreement	Exhibit 99.1 of Murphy’s Form 10-Q report filed November 6, 2013

Exhibit No.		Incorporated by Reference to
99.4	Form of non-employee director stock option	Exhibit 99.3 of Murphy’s Form 10-K report for the year ended December 31, 2010
99.5	Form of non-employee director restricted stock unit award	Exhibit 99.5 of Murphy’s Form 10-K report for the year ended December 31, 2008
99.6	Form of non-employee director restricted stock unit award	Exhibit 99.2 of Murphy’s Form 10-Q report filed November 6, 2013
99.7	Form of phantom unit award	Exhibit 99.1 of Murphy’s Form 10-Q report filed November 6, 2012
99.8	Form of stock appreciation right (“SAR”)	Exhibit 99.6 of Murphy’s Form 10-K report for the year ended December 31, 2012 and Exhibit 99.3 of Murphy's Form 10-Q report filed May 7, 2014
99.9	Form of performance-based restricted stock unit-cash grant agreement	Exhibit 99.7 of Murphy’s Form 10-K report for the year ended December 31, 2012
99.10	Form of time-based restricted stock unit grant agreement	Exhibit 99.1 of Murphy's Form 10-Q report filed May 7, 2014
99.11	Form of time-based restricted stock unit – cash grant agreement	Exhibit 99.2 of Murphy's Form 10-Q report filed May 7, 2014
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema Document	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

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SIGNATURES

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

MURPHY OIL CORPORATION

By /s/ ROGER W. JENKINS Date: February 27, 2015
Roger W. Jenkins, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 27, 2015 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ Claiborne P. Deming Claiborne P. Deming, Chairman and Director	/s/ R. Madison Murphy R. Madison Murphy, Director
/s/ ROGER W. JENKINS Roger W. Jenkins, President and Chief Executive Officer and Director (Principal Executive Officer)	/s/ Jeffrey W. Nolan Jeffrey W. Nolan, Director
/s/ Frank W. Blue Frank W. Blue, Director	/s/ Neal E. Schmale Neal E. Schmale, Director
/s/ T. Jay Collins T. Jay Collins, Director	/s/ Laura A. Sugg Laura A. Sugg, Director
/s/ Steven A. Cossé Steven A. Cossé, Director	/s/ Caroline G. Theus Caroline G. Theus, Director
/s/ Lawrence R. Dickerson Lawrence R. Dickerson, Director	/s/ Kevin G. Fitzgerald Kevin G. Fitzgerald, Executive Vice President

	and Chief Financial Officer (Principal Financial Officer)
/s/ James V. Kelley James V. Kelley, Director	/s/ John W. Eckart John W. Eckart Senior Vice President and Controller (Principal Accounting Officer)
/s/ Walentin Mirosh Walentin Mirosh, Director	

REPORT OF MANAGEMENT – CONSOLIDATED FINANCIAL STATEMENTS

The management of Murphy Oil Corporation is responsible for the preparation and integrity of the accompanying consolidated financial statements and other financial data. The statements were prepared in conformity with U.S. generally accepted accounting principles appropriate in the circumstances and include some amounts based on informed estimates and judgments, with consideration given to materiality.

An independent registered public accounting firm, KPMG LLP, has audited the Company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board and provides an objective, independent opinion about the Company's consolidated financial statements. The Audit Committee of the Board of Directors appoints the independent registered public accounting firm; ratification of the appointment is solicited annually from the shareholders. KPMG LLP's opinion covering the Company's consolidated financial statements can be found on page F-2.

The Board of Directors appoints an Audit Committee annually to implement and to support the Board's oversight function of the Company's financial reporting, accounting policies, internal controls and independent registered public accounting firm. This Committee is composed solely of directors who are not employees of the Company. The Committee meets routinely with representatives of management, the Company's audit staff and the independent registered public accounting firm to review and discuss the adequacy and effectiveness of the Company's internal controls, the quality and clarity of its financial reporting, the scope and results of independent and internal audits, and to fulfill other responsibilities included in the Committee's Charter. The independent registered public accounting firm and the Company's audit staff have unrestricted access to the Committee, without management presence, to discuss audit findings and other financial matters.

REPORT OF MANAGEMENT – INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). The Company's internal controls have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements in accordance with U.S. generally accepted accounting principles. All internal control systems have inherent limitations, and therefore, can provide only reasonable assurance with respect to the reliability of financial reporting and preparation of consolidated financial statements.

Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.

KPMG LLP has performed an audit of the Company's internal control over financial reporting and their opinion thereon can be found on page F-3.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2014. In connection with our audits of the consolidated financial statements, we also have audited financial statement Schedule II. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Murphy Oil Corporation and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Murphy Oil Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas

February 27, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited Murphy Oil Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Murphy Oil Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Murphy Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Murphy Oil Corporation as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2014, and our report dated February 27, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas

February 27, 2015

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars)	2014	2013
Assets		
Current assets		
Cash and cash equivalents	$ 1,193,308	750,155
Canadian government securities with maturities greater than 90 days at the date of acquisition	461,313	374,842
Accounts receivable, less allowance for doubtful accounts of $1,609 in both 2014 and 2013	873,277	999,872
Inventories, at lower of cost or market	242,733	294,195
Prepaid expenses	77,281	83,856
Deferred income taxes	55,107	61,991
Assets held for sale	376,130	943,732
Total current assets	3,279,149	3,508,643
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $9,503,524 in 2014 and $8,540,239 in 2013	13,331,047	13,481,055
Goodwill	–	40,259
Deferred charges and other assets	81,151	98,123
Assets held for sale	50,960	381,404
Total assets	$ 16,742,307	17,509,484
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 465,388	26,249
Accounts payable	2,275,830	2,158,485
Income taxes payable	59,054	222,930
Other taxes payable	52,457	33,969
Other accrued liabilities	143,610	143,258
Liabilities associated with assets held for sale	151,548	639,140
Total current liabilities	3,147,887	3,224,031
Long-term debt, including capital lease obligation	2,536,238	2,936,563
Deferred income taxes	1,193,864	1,466,100
Asset retirement obligations	841,526	852,488
Deferred credits and other liabilities	441,048	339,028
Liabilities associated with assets held for sale	8,310	95,544
Stockholders’ equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	–	–

Common Stock, par $1.00, authorized 450,000,000 shares, issued		
195,040,149 shares in 2014 and 194,920,155 shares in 2013	195,040	194,920
Capital in excess of par value	906,741	902,633
Retained earnings	8,728,032	8,058,792
Accumulated other comprehensive income (loss)	(170,255)	172,119
Treasury stock	(1,086,124)	(732,734)
Total stockholders' equity	8,573,434	8,595,730
Total liabilities and stockholders' equity	$ 16,742,307	17,509,484

See notes to consolidated financial statements, page F-9.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 (Thousands of dollars except per share amounts)	2014	2013	2012
Revenues			
Sales and other operating revenues	$ 5,288,933	5,312,686	4,608,563
Gain (loss) on sale of assets	138,903	(87)	66
Interest and other income	48,248	77,490	10,973
Total revenues	5,476,084	5,390,089	4,619,602
Costs and Expenses			
Lease operating expenses	1,089,888	1,252,812	1,079,136
Severance and ad valorem taxes	107,215	87,331	35,612
Exploration expenses, including undeveloped lease amortization	513,600	502,215	380,924
Selling and general expenses	364,004	379,167	249,532
Depreciation, depletion and amortization	1,906,247	1,553,394	1,253,095
Impairment of assets	51,314	21,587	200,000
Accretion of asset retirement obligations	50,778	48,996	38,361
Interest expense	136,424	124,423	54,105
Interest capitalized	(20,605)	(52,523)	(39,173)
Other expense	24,949	–	–
Total costs and expenses	4,223,814	3,917,402	3,251,592
Income from continuing operations before income taxes	1,252,270	1,472,687	1,368,010
Income tax expense	227,297	584,550	561,516
Income from continuing operations	1,024,973	888,137	806,494
Income (loss) from discontinued operations, net of income taxes	(119,362)	235,336	164,382
Net Income	$ 905,611	1,123,473	970,876
Income per Common Share – Basic			
Income from continuing operations	$ 5.73	4.73	4.16
Income (loss) from discontinued operations	(0.67)	1.25	0.85
Net income – Basic	$ 5.06	5.98	5.01
Income per Common Share – Diluted			
Income from continuing operations	$ 5.69	4.69	4.14
Income (loss) from discontinued operations	(0.66)	1.25	0.85
Net income – Diluted	$ 5.03	5.94	4.99

Average Common shares outstanding – basic	178,852,942	187,921,062	193,902,335
Average Common shares outstanding – diluted	180,070,984	189,271,398	194,668,737

See notes to consolidated financial statements, page F-9.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 (Thousands of dollars)	2014	2013	2012
Net income	$ 905,611	1,123,473	970,876
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	(271,491)	(308,300)	117,331
Retirement and postretirement benefit plans	(72,796)	69,583	(17,650)
Deferred loss on interest rate hedges:			
Increase in deferred loss associated with contract revaluation and settlement	–	–	(2,407)
Amount of loss reclassified to interest expense in consolidated statement of income	1,913	1,935	1,207
Other comprehensive income (loss)	(342,374)	(236,782)	98,481
Comprehensive Income	$ 563,237	886,691	1,069,357

See notes to consolidated financial statements, page F-9.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of dollars)	2014	2013	2012
Operating Activities			
Net income	$ 905,611	1,123,473	970,876
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss (income) from discontinued operations	119,362	(235,336)	(164,382)
Depreciation, depletion and amortization	1,906,247	1,553,394	1,253,095
Impairment of assets	51,314	21,587	200,000
Amortization of deferred major repair costs	8,345	8,464	7,065
Dry hole costs	269,986	262,876	181,924
Amortization of undeveloped leases	74,438	66,891	129,750
Accretion of asset retirement obligations	50,778	48,996	38,361
Deferred and noncurrent income tax charges (benefits)	(170,915)	158,108	342,718
Pretax (gains) losses from disposition of assets	(138,903)	87	(66)
Net decrease (increase) in noncash operating working capital	(3,729)	266,329	(168,180)
Other operating activities – net	(23,895)	(64,174)	120,219
Net cash provided by continuing operations	3,048,639	3,210,695	2,911,380
Investing Activities			
Property additions and dry hole costs1	(3,679,464)	(3,590,344)	(3,541,724)
Proceeds from sales of property, plant and equipment	1,467,046	1,650	99
Purchase of investment securities2	(986,328)	(923,497)	(1,619,308)
Proceeds from maturity of investment securities2	899,857	664,258	2,035,798
Other investing activities – net	(18,929)	291	253
Net cash required by investing activities	(2,317,818)	(3,847,642)	(3,124,882)
Financing Activities			
Borrowings of debt1	100,000	350,000	1,995,467
Repayments of debt	–	–	(350,000)
Repayment of capital lease obligation	(25,265)	–	–
Purchase of treasury stock	(375,000)	(500,000)	(250,000)
Proceeds from exercise of stock options and employee stock purchase plans	210	3,409	12,324
Withholding tax on stock-based incentive awards	(6,786)	(16,727)	(3,341)
Cash dividends paid	(236,371)	(235,108)	(714,429)
Separation of U.S. retail marketing business:			
Cash distributed to Murphy Oil by Murphy USA	–	650,000	–
Cash held and retained by Murphy USA upon separation	–	(55,506)	–
Other – net	(1,498)	(2,473)	(4,312)
Net cash provided (required) by financing activities	(544,710)	193,595	685,709
Cash Flows from Discontinued Operations			

Operating activities	(39,563)	427,792	144,901
Investing activities	199,541	116,463	(192,540)
Changes in cash included in current assets held for sale	100,790	(301,302)	–
Net increase (decrease) in cash and cash equivalents of discontinued operations	260,768	242,953	(47,639)
Effect of exchange rate changes on cash and cash equivalents	(3,726)	3,238	8,875
Net increase (decrease) in cash and cash equivalents	443,153	(197,161)	433,443
Cash and cash equivalents at January 1	750,155	947,316	513,873
Cash and cash equivalents at December 31	$ 1,193,308	750,155	947,316

1Excludes non-cash asset and long-term obligation of $357,991 in 2013 associated with lease commencement for production equipment at the Kakap field offshore Malaysia.

2Investments are Canadian government securities with maturities greater than 90 days at the date of acquisition.

See notes to consolidated financial statements, page F-9.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Years Ended December 31 (Thousands of dollars)	2014	2013	2012
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ –	–	–
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2014, 2013 and 2012, issued 195,040,149 shares at December 31, 2014, 194,920,155 shares at December 31, 2013 and 194,616,470 shares at December 31, 2012			
Balance at beginning of year	194,920	194,616	193,909
Exercise of stock options	120	304	483
Awarded restricted stock	–	–	224
Balance at end of year	195,040	194,920	194,616
Capital in Excess of Par Value			
Balance at beginning of year	902,633	873,934	817,974
Exercise of stock options, including income tax benefits	(11,422)	563	12,717
Restricted stock transactions	(27,920)	(28,339)	(5,257)
Stock-based compensation	43,490	56,622	46,584
Sale of stock under employee stock purchase plans	(40)	(147)	1,916
Balance at end of year	906,741	902,633	873,934
Retained Earnings			
Balance at beginning of year	8,058,792	7,717,389	7,460,942
Net income for the year	905,611	1,123,473	970,876
Cash dividends – $1.325 per share in 2014, $1.25 per share in 2013 and $3.675 per share in 2012	(236,371)	(235,108)	(714,429)
Distribution of common stock of Murphy USA Inc. to shareholders	–	(546,962)	–
Balance at end of year	8,728,032	8,058,792	7,717,389
Accumulated Other Comprehensive Income (Loss)			
Balance at beginning of year	172,119	408,901	310,420
Foreign currency translation gains (losses), net of income taxes	(271,491)	(308,300)	117,331
Retirement and postretirement benefit plans, net of income taxes	(72,796)	69,583	(17,650)
Change in deferred loss on interest rate hedges, net of income taxes	1,913	1,935	(1,200)
Balance at end of year	(170,255)	172,119	408,901
Treasury Stock			

Balance at beginning of year	(732,734)	(252,805)	(4,848)
Purchase of treasury shares	(375,000)	(500,000)	(250,000)
Sale of stock under employee stock purchase plans	420	1,015	2,043
Awarded restricted stock	21,190	19,056	–
Balance at end of year – 17,540,636 shares of Common Stock in 2014, 11,513,642 shares of Common Stock in 2013 and 3,975,153 shares of Common Stock in 2012	(1,086,124)	(732,734)	(252,805)
Total Stockholders' Equity	$ 8,573,434	8,595,730	8,942,035

See notes to consolidated financial statements, page F-9.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A – Significant Accounting Policies

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company produces oil and natural gas in the United States, Canada and Malaysia and conducts oil and natural gas exploration activities worldwide. The Company has an interest in a Canadian synthetic oil operation. On August 30, 2013, the Company spun off Murphy USA Inc. (MUSA) to its shareholders. MUSA formerly was the Company's U.S. gasoline retail marketing operations. MUSA is now a separate, publicly owned company traded on the New York Stock Exchange under the symbol "MUSA." In addition, Murphy Oil sold its United Kingdom retail marketing assets during 2014 and sold its U.K. oil and natural gas producing assets during 2013. The Company is in the process of selling components of and decommissioning a crude oil refinery in the U.K. that was shutdown in May 2014. It also is marketing for sale four U.K. petroleum product terminals as of December 31, 2014. See Note C regarding more information regarding the spin-off and sale of these assets.

PRINCIPLES OF CONSOLIDATION – The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. Investments in affiliates in which the Company owns from 20% to 50% are accounted for by the equity method. Other investments are generally carried at cost. All significant intercompany accounts and transactions have been eliminated.

REVENUE RECOGNITION – Revenues from sales of crude oil, natural gas liquids, natural gas and refined petroleum products are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Natural gas imbalances occur when the Company's actual gas sales volumes differ from its entitlement under existing working interests. The Company records a liability for gas imbalances when it has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2014 and 2013, the liabilities for natural gas balancing were immaterial.

CASH EQUIVALENTS – Short-term investments, which include government securities and other instruments with government securities as collateral, that are highly liquid and have a maturity of three months or less from the date of purchase are classified as cash equivalents.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

MARKETABLE SECURITIES – The Company classifies investments in marketable securities as available-for-sale or held-to-maturity. The Company does not have any investments classified as trading securities. Available-for-sale securities are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive income. Held-to-maturity securities are recorded at amortized cost. Premiums and discounts are amortized or accreted into earnings over the life of the related available-for-sale or held-to-maturity security.

Dividend and interest income is recognized when earned. Unrealized losses considered to be other than temporary are recognized currently in earnings. The cost of securities sold is based on the specific identification method. The fair value of investment securities is determined by available market prices. At December 31, 2014, the Company owned Canadian government securities with maturities greater than 90 days at date of acquisition that had a carrying value of $461,313,000. These securities are readily marketable and could be quickly converted to cash if needed to meet operating cash needs in Canada.

ACCOUNTS RECEIVABLE – At December 31, 2014 and 2013, the Company's accounts receivable primarily consisted of amounts owed to the Company by customers for sales of crude oil and natural gas. The allowance for doubtful accounts is the Company's best estimate of the amount of probable credit losses on these receivables. The Company reviews this allowance for adequacy at least quarterly and bases its assessment on a combination of current information about its customers and historical write-off experience. Any trade accounts receivable balances written off are charged against the allowance for doubtful accounts. The Company has not experienced any significant credit-related losses in the past three years.

INVENTORIES – Amounts included in the Consolidated Balance Sheets include unsold crude oil production and materials and supplies associated with oil and gas production operations. Unsold crude oil production is carried in inventory at the lower of cost, generally applied on a first-in, first-out (FIFO) basis, or market, and includes costs incurred to bring the inventory to its existing condition. Materials and supplies inventories are valued at the lower of average cost or estimated value and generally consist of tubulars and other drilling equipment.

PROPERTY, PLANT AND EQUIPMENT – The Company uses the successful efforts method to account for exploration and development expenditures. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Costs of undeveloped leases associated with unproved properties are expensed over the life of the leases. Exploratory well costs are capitalized pending determination about whether proved reserves have been found. In certain cases, a determination of whether a drilled exploratory well has found proved reserves cannot be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is usually dependent on whether further exploratory wells find a sufficient quantity of additional reserves. The Company continues to capitalize exploratory well costs in Property, Plant and Equipment when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the

Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The Company reevaluates its capitalized drilling costs at least annually to ascertain whether drilling costs continue to qualify for ongoing capitalization. Other exploratory costs, including geological and geophysical costs, are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized. Interest is capitalized on significant development projects that are expected to take one year or more to complete.

Oil and gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment is recognized when the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset is reduced to fair value.

The Company records a liability for asset retirement obligations (ARO) equal to the fair value of the estimated cost to retire an asset. The ARO liability is initially recorded in the period in which the obligation meets the definition of a liability, which is generally when a well is drilled or the asset is placed in service. The ARO liability is estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is increased over time to reflect the change in its present value, and the capitalized cost is depreciated over the useful life of the related long-lived asset. The Company reevaluates the adequacy of its recorded ARO liability at least annually. Actual costs of asset retirements such as dismantling oil and gas production facilities and site restoration are charged against the related liability. Any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company's earnings.

Depreciation and depletion of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized exploration drilling and development costs using proved developed reserves; unit rates for unamortized leasehold costs and asset retirement costs are amortized over proved reserves. Proved reserves are estimated by the Company's engineers and are subject to future revisions based on availability of additional information. Additionally, certain natural gas processing facilities and related equipment in Malaysia and Canada are being depreciated on a straight-line basis over its estimated useful life ranging from 20 to 25 years. Gains and losses on asset disposals or retirements are included in income as a separate component of revenues.

Turnarounds for coking units at Syncrude Canada Ltd. are scheduled at intervals of two to three years. Turnaround work associated with various other less significant units at Syncrude varies depending on operating requirements and events. Murphy defers turnaround costs incurred and amortizes such costs over the period until the next scheduled turnaround. This amortization is recorded in Lease Operating Expenses for Syncrude. All other maintenance and repairs are expensed as incurred. Renewals and betterments are capitalized.

Capitalized Interest – Interest associated with borrowings from third parties is capitalized on significant oil and gas development projects when the expected development period extends for one year or more. Interest capitalized is credited in the Consolidated Statement of Income and is added to the cost of the underlying asset for the development project in Property, Plant and Equipment in the Consolidated Balance Sheet. Capitalized interest is amortized over the useful life of the asset in the same manner as other development costs.

GOODWILL – Goodwill is recorded in an acquisition when the purchase price exceeds the fair value of net assets acquired. All recorded goodwill arose from the purchase of an oil and natural gas company by Murphy's wholly owned Canadian subsidiary in 2000. Goodwill is not amortized, but is assessed annually for recoverability of the carrying value. The Company assesses goodwill recoverability at each year-end by comparing the fair value of net assets for conventional oil and natural gas properties in Canada with the carrying value of these net assets including goodwill. The fair value of the conventional oil and natural gas reporting unit is determined using the expected present value of future cash flows. Based on its assessment of the fair value of its Canadian conventional oil and natural gas operations, the Company recorded an impairment charge of $37,047,000 in the fourth quarter 2014 and reduced the carrying amount to zero.

ENVIRONMENTAL LIABILITIES – A liability for environmental matters is established when it is probable that an environmental obligation exists and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Related expenditures are charged against the liability. Environmental remediation liabilities have not been discounted for the time value of future expected payments. Environmental expenditures that have future economic benefit are capitalized.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

INCOME TAXES – The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities based on differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. The Company routinely assesses the realizability of deferred tax assets based on available evidence including assumptions of future taxable income, tax planning strategies and other pertinent factors. A deferred tax asset valuation allowance is recorded when evidence indicates that it is more likely than not that all or a portion of these deferred tax assets will not be realized in a future period. The Company does not provide U.S. deferred taxes for the portion of undistributed earnings of foreign subsidiaries when these earnings are considered indefinitely reinvested in the respective foreign operations. The accounting rules for income tax uncertainties permit recognition of income tax benefits only when they are more likely than not to be realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

FOREIGN CURRENCY – Local currency is the functional currency used for recording operations in Canada and for former refining and marketing activities in the United Kingdom. The U.S. dollar is the functional currency used to record all other operations. Exchange gains or losses from transactions in a currency other than the functional currency are included in earnings. Gains or losses from translating foreign functional currencies into U.S. dollars are included in Accumulated Other Comprehensive Income (Loss) in Stockholders’ Equity.

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES – The fair value of a derivative instrument is recognized as an asset or liability in the Company’s Consolidated Balance Sheet. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge for accounting purposes, and thenceforth, recognize changes in the fair value of the contract in earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis whether a derivative instrument accounted for as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. The change in the fair value of a qualifying fair value hedge is recorded in earnings along with the gain or loss on the hedged item. The effective portion of the change in the fair value of a qualifying cash flow hedge is recorded in other comprehensive income until the hedged item is recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge and the underlying forecasted transaction is no longer probable of occurring, hedge accounting is discontinued and the gain or loss recorded in other comprehensive income is recognized immediately in earnings.

Fair Value Measurements – The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheet. Fair value is determined using various techniques depending on the availability of observable inputs. Level 1 inputs include quoted prices in active markets for identical assets or liabilities. Level 2 inputs include observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

STOCK-BASED COMPENSATION

Equity-Settled Awards – The fair value of awarded stock options, restricted stock units and other stock-based compensation that are settled with Company shares is determined based on a combination of management assumptions and the market value of the Company's common stock. The Company uses the Black-Scholes option pricing model for computing the fair value of equity-settled stock options. The primary assumptions made by management include the expected life of the stock option award and the expected volatility of Murphy's common stock prices. The Company uses both historical data and current information to support its assumptions. Stock option expense is recognized on a straight-line basis over the respective vesting period of two or three years. The Company uses a Monte Carlo valuation model to determine the fair value of performance-based restricted stock units that are equity settled and expense is recognized over the three-year vesting period. The fair value of time-lapse restricted stock units is determined based on the price of Company stock on the date of grant and expense is recognized over the three-year vesting period. The Company estimates the number of stock options and performance-based restricted stock units that will not vest and adjusts its compensation expense accordingly. Differences between estimated and actual vested amounts are accounted for as an adjustment to expense when known.

Cash-Settled Awards – The Company accounts for stock appreciation rights (SAR), cash-settled restricted stock units (CRSU) and phantom stock units as liability awards. Expense associated with these awards are recognized over the vesting period based on the latest available estimate of the fair value of the awards, which is generally determined using a Black-Scholes method for SAR, a Monte Carlo method for performance-based CRSU, and the period-end price of the Company's common stock for time-based CRSU and phantom units. When SAR are exercised and when CRSU and phantom units settle, the Company adjusts previously recorded expense to the final amounts paid out in cash for these awards.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS – The Company recognizes the funded status (the difference between the fair value of plan assets and the projected benefit obligation) of its defined benefit and other postretirement benefit plans in the Consolidated Balance Sheet. Changes in the funded status which have not yet been recognized in the Statement of Income are recorded net of tax in Accumulated Other Comprehensive Income (Loss). The remaining amounts in Accumulated Other Comprehensive Income (Loss) as of December 31, 2014 include net actuarial losses and prior service costs.

NET INCOME PER COMMON SHARE – Basic income per common share is computed by dividing net income for each reporting period by the weighted average number of common shares outstanding during the period. Diluted income per common share is computed by dividing net income for each reporting period by the weighted average number of common shares outstanding during the period plus the effects of all potentially dilutive common shares.

RECLASSIFICATIONS – The Consolidated Balance Sheet for 2013 has been reclassified to conform to the 2014 presentation within current liabilities. The Consolidated Statements of Income for 2013 and 2012 have been reclassified to disclose separately Lease Operating Expenses and Severance and Ad valorem Taxes and to conform to 2014 presentation. The Consolidated Statements of Cash Flows have been reclassified in 2013 and 2012 to conform to the 2014 presentation of all cash flow impacts of discontinued operations in a separate category in the statement below financing activities.

USE OF ESTIMATES – In preparing the financial statements of the Company in conformity with U.S. generally accepted accounting principles, management has made a number of estimates and assumptions related to the reporting of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Actual results may differ from the estimates.

Note B – New Accounting Principles and Recent Accounting Pronouncements

The Company did not adopt any new accounting pronouncements in 2014 that had a significant effect on its consolidated financial statements.

Recent Accounting Pronouncements

Three new Accounting Standards Updates (ASU) were issued during 2014 by the Financial Accounting Standards Board (FASB) that must be adopted in the future.

In August 2014, the FASB issued an ASU requiring, when applicable, disclosures regarding uncertainties about an entity's ability to continue as a going concern. During the preparation of quarterly and annual financial statements, management should evaluate whether conditions or events exist that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date the financial statements are issued. If this evaluation indicates that it is probable that an entity will be unable to meet its obligations when they become due within one year of the financial statement issuance date, management must evaluate whether its mitigation plans will alleviate the substantial doubt of continuing as a going concern. If substantial doubt exists, regardless of whether the mitigation plan alleviates the concern, additional disclosures are required in the financial statements addressing the conditions or events that raise substantial doubt, management's evaluation of the significance of those conditions or events, and management's mitigation plans. This new guidance will become effective for the Company for all reporting periods beginning in 2016. Early application is permitted. Company management currently does not expect that this new guidance will have a significant effect on its consolidated financial statements when adopted.

In May 2014, the FASB issued an ASU addressing recognition of revenue from contracts with customers. When adopted, this guidance will supersede current revenue recognition rules currently followed by the Company. The core principle of the new ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The ASU provides five steps for an entity to apply in recognizing revenue, including: (1) identify the customer contract; (2) identify the contractual performance obligations; (3) determine the transaction price; (4) allocate the transaction price to the contractual performance obligations; and (5) recognize revenue when the performance obligation is satisfied. The new ASU also requires additional disclosures regarding significant contracts with customers. The new ASU will be effective for the Company on January 1, 2017, and early adoption is not permitted. For transition purposes, the new ASU permits either (a) a retrospective application to all years presented, or (b) an alternative transition method whereby the new guidance is only applied to contracts not completed at the date of initial application. The vast majority of the Company's revenue is recognized when oil and natural gas produced by the Company is delivered and legal ownership of these products has transferred to the purchaser. Based on the Company's present understanding, the accounting for oil and gas sales revenue is not expected to be significantly altered by the new ASU. The Company has not yet selected which transition method it will use.

In April 2014, the FASB issued an ASU that will change the requirements for reporting discontinued operations after its adoption. Under the new guidance, only disposals of components of an entity that represent a strategic shift that has or will have a major effect on an entity's operations and financial results will be reported as discontinued operations in the financial statements. Under prior guidance, a component of an entity that is a reportable segment, an operating segment, a reporting unit, a subsidiary, or an asset group that has been or will be eliminated from ongoing operations and for which the Company will not have any significant continuing involvement with the component after the disposal was generally reported as discontinued operations. The FASB anticipates that fewer component disposals will be reported as discontinued operations under the new guidance. The new guidance also requires expanded disclosures about discontinued operations. The new guidance will be effective for the Company beginning in 2015. The new guidance is not to be applied to a component that is classified as held for sale before the effective date of the guidance.

Note C – Discontinued Operations

Separation of U.S. Downstream Business

On August 30, 2013, Murphy Oil Corporation (the "Company") distributed 100% of the outstanding common stock of Murphy USA Inc. ("MUSA") to its shareholders in a generally tax-free spin-off for U.S. federal income tax purposes. After the close of the New York Stock Exchange on August 30, 2013, the Company's shareholders of record as of 5:00 p.m. Eastern time on August 21, 2013 received one share of MUSA common stock for every four common shares of the Company held by such shareholders. Prior to the separation, MUSA held all of the Company's U.S. downstream operations, including retail gasoline stations and other marketing assets, plus two ethanol production facilities. In connection with the separation, Murphy Oil USA, Inc., MUSA's 100% owned primary operating subsidiary, distributed $650,000,000 to the Company in the form of a cash dividend. The shares of MUSA common stock are traded on the New York Stock Exchange under the ticker symbol "MUSA." The Company has no continuing involvement with MUSA operations. Accordingly, the operating results and the cash flows for these former U.S. downstream operations have been reported as discontinued operations for all periods presented in the consolidated financial statements. These operations were formerly reported as the U.S. refining and marketing segment in prior years' financial statements.

In order to effect the separation and govern the Company's relationship with MUSA after the separation, both parties entered into a series of agreements governing each party's rights and obligations after the separation. Among such agreements, the Separation and Distribution Agreement governs the separation of the U.S. downstream business, the transfer of assets, cross-indemnities between the Company and MUSA, handling of claims subject to indemnification and related matters, and other matters related to the Company's relationship with MUSA.

The Tax Matters Agreement governs the respective rights, responsibilities and obligations of the Company and MUSA with respect to taxes, tax attributes, tax returns, tax proceedings and certain other tax matters. In addition, the Tax Matters Agreement imposes certain restrictions on MUSA and its subsidiaries (including restrictions on share issuances, business combinations, sales of assets and similar transactions) that are designed to preserve the tax-free status of the distribution.

The Employee Matters Agreement governs the compensation and employee benefit obligations with respect to the current and former employees and non-employee directors of the Company and MUSA, and generally allocates liabilities and responsibilities relating to employee compensation, benefit plans and programs. The Employee Matters Agreement provides that employees of MUSA will no longer participate in benefit plans sponsored or maintained by the Company. In addition, the Employee Matters Agreement provides that each of the parties will be responsible for their respective current employees and compensation plans for such current employees, and that the Company will be responsible for liabilities relating to former employees who left prior to the separation. The Employee Matters

Agreement sets forth the general principles relating to employee matters and also addresses any special circumstances during the transition period. The Employee Matters Agreement also provides that (i) the distribution does not constitute a change in control under existing plans, programs, agreements or arrangements, and (ii) the distribution and the assignment, transfer or continuation of the employment of employees with another entity will not constitute a severance event under the applicable plans, programs, agreements or arrangements.

The Transition Service Agreement sets forth the terms on which the Company and MUSA will provide certain services or functions to the other party. Transition services include administration, payroll, human resources, data processing, environmental health and safety, audit support, financial transaction support, and other support services, information technology systems and various other corporate services. The agreement provides for the provision of specified services, generally for a period of up to 18 months, with a possible extension of six months (an aggregate of 24 months), on a full cost basis.

Other Discontinued Operations

The Company sold all of its U.K. oil and natural gas production assets during 2013, and recognized an after-tax gain of $216,147,000 on sale of these assets. The results of these operations have been reported as discontinued operations for all periods presented in these consolidated financial statements.

On September 30, 2014, the Company sold its U.K. retail marketing operations and associated inventories with total proceeds of $211,965,000. The Company was unable to sell the Milford Haven, Wales, refinery after an extensive marketing effort proved unsuccessful. The refinery ceased processing crude oil in May 2014, and the refinery portion of the Milford Haven facility is in the process of being decommissioned. The Company is marketing for sale the products terminal portion of the Milford Haven facility along with three U.K. inland product terminals. The Company has accounted for this U.K. downstream business as discontinued operations for all periods presented.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

The following table presents the carrying value of the major categories of assets and liabilities of discontinued operations associated with U.K. refining and marketing operations that are reflected on the Company's consolidated balance sheets at December 31, 2014 and 2013:

(Millions of dollars)	2014	2013
Current assets		
Cash	$ 200,512	301,302
Accounts receivable	97,568	302,059
Inventory	42,161	254,240
Other	35,889	86,131
Total current assets held for sale	$ 376,130	943,732
Non-current assets		
Property, plant and equipment, net	$ 50,947	360,347
Other	13	21,057
Total non-current assets held for sale	$ 50,960	381,404
Current liabilities		
Accounts payable	$ 59,023	484,082
Other accrued taxes payable	40,653	130,028
Accrued compensation and severance	30,872	17,020
Refinery decommissioning cost	21,000	–
Other	–	8,010
Total current liabilities associated with assets held for sale	$ 151,548	639,140
Non-current liabilities		
Deferred income taxes payable	$ 3,873	68,096
Deferred credits and other liabilities	4,437	27,448
Total non-current liabilities associated with assets held for sale	$ 8,310	95,544

In 2014 and 2013, the Company wrote down its net investment in the held for sale U.K. refining and marketing assets by $269,200,000 and $73,000,000, respectively. The 2014 writedown was based on estimated salvage value of remaining refining and terminal assets as of the end of the year. The 2013 write down was based on an assessment of the fair value of these assets based on the status of the ongoing sale process at that time. The Company benefited in 2014 from a LIFO inventory liquidation credit of $209,600,000 and a gain on sale of the U.K. retail marketing assets of $101,700,000. These charges and benefits have been included in the results of discontinued operations.

Discontinued operations inventories accounted for under the LIFO method totaled $10,954,000 and $318,628,000 at December 31, 2014 and 2013, respectively, and these amounts were $44,881,000 and $268,608,000 less than such inventories would have been valued using the FIFO method. These inventories are carried in Current Assets Held for Sale in the Consolidated Balance Sheets at December 31, 2014 and 2013. In association with the shutdown of the Milford Haven, Wales, refinery in 2014, most crude oil inventories and a large portion of the refinery's finished products were liquidated at market values. This reduction in LIFO inventory reserve benefited discontinued operating results in 2014 as noted above.

As of December 31, 2014, the Company has recorded an Asset Retirement Obligation (ARO) for its refining assets in the U.K. that are being decommissioned. The ARO estimate for the U.K. assets is based on professional judgment associated with abandonment of major industrial assets, but is subject to change based on the availability of additional information in subsequent periods. The ARO associated with the U.K. refinery abandonment of $21,000,000 is included in Other Current Liabilities Associated with Assets Held for Sale in the Consolidated Balance Sheet at December 31, 2014.

At year-end 2012, the Company wrote down its net investment in the ethanol production facility in Hereford, Texas, taking an impairment charge of $60,988,000 in discontinued operations. The write down was required based on expected weak ethanol production margins at the plant in future periods. Fair value was determined using a discounted cash flow model for three years, plus an estimated terminal value based on a multiple of the last year's cash flow. Certain key assumptions used in the cash flow model included use of available futures prices for corn and ethanol products. Additional key assumptions included estimated future ethanol and distillers grain production levels, estimated future operating expenses, and estimated sales prices for distillers grain.

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 discontinued operations of $5,523,000 in 2012.

The results of operations associated with all discontinued operations are presented in the following table.

(Thousands of dollars)	2014	2013	2012
Revenues	$ 2,786,394	17,586,236	24,156,748
Income (loss) from operations before income taxes	$ (261,873)	119,984	330,048
Gain on sale before income taxes	101,684	130,991	–
Total income (loss) from discontinued operations before taxes	(160,189)	250,975	330,048
Income tax expense (benefit)	(40,827)	15,639	165,666
Income (loss) from discontinued operations	$ (119,362)	235,336	164,382

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note D – Inventories

Inventories consisted of the following at December 31, 2014 and 2013.

	December 31,	
	2014	2013
(Thousands of dollars)		
Unsold crude oil	$ 51,810	40,077
Materials and supplies	190,923	254,118
	$ 242,733	294,195

Note E – Property, Plant and Equipment

	December 31, 2014		December 31, 2013	
(Thousands of dollars)	Cost	Net	Cost	Net
Exploration and production1	$ 22,731,220	13,277,985 2	21,932,119	13,433,468 2
Corporate and other	103,351	53,062	89,175	47,587
	$ 22,834,571	13,331,047	22,021,294	13,481,055
1 Includes mineral rights as follows:	$ 924,253	410,482	1,007,920	489,578

2 Includes $58,334 in 2014 and $48,691 in 2013 related to administrative assets and support equipment.

In December 2014, the Company sold 20% of its oil and gas assets in Malaysia and received net cash proceeds of $1,460,425,000. The Company recorded an after-tax gain on this sale of $321,454,000 in 2014.

Under FASB guidance exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

At December 31, 2014, 2013 and 2012, the Company had total capitalized drilling costs pending the determination of proved reserves of $120,455,000, $393,030,000 and $445,697,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2014.

(Thousands of dollars)	2014	2013	2012
Beginning balance at January 1	$ 393,030	445,697	556,412
Additions to capitalized exploratory well costs pending the determination of proved reserves	2,874	57,716	135,849
Reclassifications to proved properties based on the determination of proved reserves	(91,236)	(93,936)	(165,377)
Reduction of capitalized exploratory well costs due to partial asset sale in Malaysia	(122,175)	–	–
Capitalized exploratory well costs charged to expense	(62,038)	(16,447)	(81,187)
Ending balance at December 31	$ 120,455	393,030	445,697

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs has been capitalized since the completion of drilling.

	2014			2013			2012		
(Thousands of dollars)	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:									
Zero to one year	$ –	–	–	$ 56,499	3	1	$ 59,833	7	2
One to two years	59,330	3	1	60,787	7	1	18,335	2	3
Two to three years	6,606	3	–	–	–	–	83,314	9	4
Three years or more	54,519	2	2	275,744	22	7	284,215	26	6
	$ 120,455	8	3	$ 393,030	32	9	$ 445,697	44	15

Of the $120,455,000 of exploratory well costs capitalized more than one year at December 31, 2014, $54,519,000 is in the U.S. and $65,936,000 is in Brunei. In the U.S. further drilling is anticipated and development plans are being formulated. In Brunei development options are under review for these multiple gas discoveries. The capitalized well costs charged to expense in 2014 included four gas wells in Peninsula Malaysia and one well in the Gulf of Mexico. The Company's application to extend the gas holding period for the Malaysia wells was denied by the Malaysian government in 2014. Development of the well in the Gulf of Mexico could not be justified due to the low prices for natural gas at year-end 2014. The capitalized well costs charged to expense in 2013 included two wells offshore Sarawak Malaysia that were written off due to the Company's decision not to move forward with development of the wells. The capitalized well costs charged to expense in 2012 included a suspended well in the northern block of the Republic of the Congo that was written off following unsuccessful wildcat drilling in 2012 at a nearby prospect, two suspended wells offshore Sarawak Malaysia that were written off following a decision not to continue development of the wells, and a well drilled in the Gulf of Mexico in 2010 that the owners decided not to develop.

At year-end 2014, the Company recorded an impairment writedown of property, plant and equipment in the amount of $14,267,000 related to one gas well in the Gulf of Mexico, and in 2013 an impairment writedown of $21,587,000 was recorded for properties in Western Canada. At year-end 2012, Murphy determined that the Azurite field, offshore Republic of the Congo, was impaired due to removal of all proved oil reserves after an unsuccessful redrill of a key well in the field. The impairment charge in 2012 totaled $200,000,000 and included a write-off of the remaining book value of the Azurite field plus other anticipated losses related to operations of the field. Fair value was determined at these fields using a discounted cash flow model based on certain key assumptions, including future estimated net production levels, future estimated oil prices for the field based on year-end futures prices, and future estimated operating and capital expenditures.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note F – Financing Arrangements

At December 31, 2014, the Company had a $2.0 billion committed credit facility with a major banking consortium that expires in June 2017. Borrowings under this facility bear interest at 1.25% above LIBOR based on the Company's current credit rating as of December 31, 2014. In addition, facility fees of 0.25% are charged on the full $2.0 billion commitment. In May 2013, the Company increased the capacity of the committed credit facility from $1.5 billion to $2.0 billion and extended the maturity date by one year from June 2016 to June 2017. At December 31, 2014, the Company had borrowings of $450,000,000 under this committed facility. At December 31, 2014, the Company also had uncommitted credit lines that had estimated total borrowing capacity of approximately $435,000,000. No borrowings were outstanding under these uncommitted credit lines at December 31, 2014. If necessary, the Company could borrow funds under all or certain of these uncommitted lines with various financial institutions 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.

Note G – Long-term Debt

	December 31,	
(Thousands of dollars)	2014	2013
Notes payable		
2.50% notes, due 2017	$ 550,000	550,000
3.70% notes, due 2022	600,000	600,000
4.00% notes, due 2022	500,000	500,000
7.05% notes, due 2029	250,000	250,000
5.125% notes, due 2042	350,000	350,000
Notes payable to banks, 1.4375% at December 31, 2014	450,000	350,000
Total notes payable	2,700,000	2,600,000
Unamortized discount on notes payable	(4,953)	(5,439)
Total notes payable, net of unamortized discount	2,695,047	2,594,561
Capitalized lease obligation, due through June 2028	306,579	368,251
Total debt including current maturities	3,001,626	2,962,812
Current maturities	(465,388)	(26,249)
Total long-term debt	$ 2,536,238	2,936,563

The amount of debt repayable over each of the next five years and thereafter are as follows: $465,388,000 in 2015, $16,071,000 in 2016, $566,336,000 in 2017, $17,675,000 in 2018, $18,561,000 in 2019 and $1,917,595,000 thereafter.

The capitalized lease obligation included in the above table is associated with production facilities at the Kakap field, offshore Sabah, Malaysia. The facilities are utilized by the Company under a 25-year lease that extends through 2038. Payments under this lease are owed through 2028.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note H – Asset Retirement Obligations

The asset retirement obligations liabilities (ARO) recognized by the Company at December 31, 2014 and 2013 are related to the estimated costs to dismantle and abandon its producing oil and gas properties and related equipment.

A reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligation for 2014 and 2013 is shown in the following table.

(Thousands of dollars)	2014	2013
Balance at beginning of year	$ 880,003	751,583
Accretion expense	50,778	48,996
Liabilities incurred	70,568	172,048
Revisions of previous estimates	8,278	(4,856)
Liabilities settled	(36,818)	(51,647)
Liabilities assumed by purchaser of oil and gas assets	(69,416)	–
Liabilities assumed by Murphy USA Inc. upon separation	–	(15,401)
Changes due to translation of foreign currencies	(27,665)	(20,720)
Balance at end of year	875,728	880,003
Current portion of liability at end of year*	(34,202)	(27,515)
Noncurrent portion of liability at end of year	$ 841,526	852,488

*Included in Other Accrued Liabilities on the Consolidated Balance Sheet.

The estimation of future ARO is based on a number of assumptions requiring professional judgment. The Company cannot predict the type of revisions to these assumptions that may be required in future periods due to the availability of additional information such as: prices for oil field services, technological changes, governmental requirements and other factors.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note I – Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2014 and income tax expense attributable thereto were as follows.

(Thousands of dollars)	2014	2013	2012
Income (loss) from continuing operations before income taxes			
United States	$ 179,484	(5,810)	54,275
Foreign	1,072,786	1,478,497	1,313,735
Total	$ 1,252,270	1,472,687	1,368,010
Income tax expense (benefit)			
Federal – Current	$ 25,151	(56,790)	(256,931)
– Deferred	25,444	65,883	177,325
	50,595	9,093	(79,606)
State	8,840	7,141	8,104
Foreign – Current	359,502	477,715	472,701
– Deferred	(191,640)	90,601	160,317
	167,862	568,316	633,018
Total	$ 227,297	584,550	561,516

The following table reconciles income taxes based on the U.S. statutory tax rate to the Company's income tax expense.

(Thousands of dollars)	2014	2013	2012
Income tax expense based on the U.S. statutory tax rate	$ 438,295	515,440	478,804
Foreign income subject to foreign tax rates different than the U.S. statutory rate	20,562	31,752	7,710
State income taxes, net of federal benefit	5,746	4,642	5,268
U.S. tax benefit on certain foreign upstream investments	(95,838)	(133,526)	(108,077)
Deferred tax benefit on sale of Malaysian assets	(176,661)	–	–
	37,712	129,588	87,558

Increase in deferred tax asset valuation allowance related to other foreign exploration expenditures			
Impairment or abandonment of Azurite field with no tax benefit	–	35,475	70,000
Other, net	(2,519)	1,179	20,253
Total	$ 227,297	584,550	561,516

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2014 and 2013 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	2014	2013
Deferred tax assets		
Property and leasehold costs	$ 379,577	708,947
Liabilities for dismantlements	85,544	79,111
Postretirement and other employee benefits	208,600	175,446
Alternative minimum tax	46,792	49,536
Foreign tax credit carryforwards	44,061	19,896
Other deferred tax assets	22,426	23,352
Total gross deferred tax assets	787,000	1,056,288
Less valuation allowance	(306,463)	(633,735)
Net deferred tax assets	480,537	422,553
Deferred tax liabilities		
Property, plant and equipment	(479,677)	(747,561)
Accumulated depreciation, depletion and amortization	(1,123,864)	(1,040,251)
Other deferred tax liabilities	(15,753)	(38,849)
Total gross deferred tax liabilities	(1,619,294)	(1,826,661)
Net deferred tax liabilities	$ (1,138,757)	(1,404,108)

In management's judgment, the net deferred tax assets in the preceding table will more likely than not be realized as reductions of future taxable income or by utilizing available tax planning strategies. The valuation allowance for deferred tax assets relates primarily to tax assets arising in foreign tax jurisdictions and foreign tax credit carryforwards. In the judgment of management at the present time, these tax assets are not likely to be realized. The foreign tax credit carryforwards expire in 2015 through 2024. The valuation allowance decreased $327,272,000 in 2014. The deferred tax valuation allowance decreased by $65,384,000 in 2014 due to sanction of the Block H development plan, which allowed recognition of deferred tax benefits that were fully reserved in prior years. Additionally, the decrease included realization of U.S. tax benefits related to certain foreign upstream investments where the Company has exited. The remainder of the valuation allowance reduction offset changes in certain deferred tax assets. Subsequent reductions of the valuation allowance are expected to be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has not recognized a deferred tax liability for undistributed earnings of its Canadian, Malaysian and certain other foreign subsidiaries because such earnings are considered indefinitely reinvested in foreign countries. As of December 31, 2014, undistributed earnings of the Company's subsidiaries considered indefinitely reinvested were approximately $6,045,000,000. The unrecognized deferred tax liability is dependent on many factors including withholding taxes under current tax treaties and foreign tax credits and is estimated to be approximately $684,000,000. The Company does not consider undistributed earnings from certain other international operations to be indefinitely reinvested; however, any estimated tax liabilities upon repatriation of earnings from these international operations are expected to be offset with foreign tax credits. Although the Company does not foresee repatriating earnings considered indefinitely reinvested, under present law, it would incur a 5% withholding tax on any monies repatriated from Canada to the United States.

During 2014, the Company sold its U.K. retail marketing assets as well as 20% of its oil and gas assets in Malaysia. Following these sales, the Company repatriated cash from the U.K. and Malaysia of $250,000,000 and $1,700,000,000, respectively. Foreign tax credits were available to cover most of the U.S. income taxes associated with these repatriated funds. The Company continues to assert that the previously generated earnings in Malaysia are indefinitely reinvested as of December 31, 2014.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Uncertain Income Tax Positions

The FASB's rules for accounting for income tax uncertainties clarify the criteria for recognizing uncertain income tax benefits and require additional disclosures about uncertain tax positions. Under current rules the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon audit by the applicable taxing authority. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. Liabilities associated with uncertain income tax positions are included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheet. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the three years ended December 31, 2014 is shown in the following table.

(Thousands of dollars)	2014	2013	2012
Balance at January 1	$ 6,366	16,611	18,857
Additions for tax positions related to current year	988	2,486	1,258
Settlements due to lapse of time	(1,225)	(12,731)	(3,504)
Foreign currency translation effect	(118)	–	–
Balance at December 31	$ 6,011	6,366	16,611

All additions or reductions to the above liability affect the Company's effective income tax rate in the respective period of change. The Company accounts for any applicable interest and penalties on uncertain tax positions as a component of income tax expense. The Company also had other recorded liabilities as of December 31, 2014 and 2013 for interest and penalties of $142,000 and $146,000, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2014, 2013 and 2012 included net benefits for interest and penalties of $4,000, $829,000 and $1,000, respectively, associated with uncertain tax positions.

During the next twelve months, the Company currently expects to add between $1,000,000 and $2,000,000 to the liability for uncertain taxes for 2015 events. Although existing liabilities could be reduced by settlement with taxing authorities or lapse due to statute of limitations, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statement of Income during 2015.

The Company's tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters. As of December 31, 2014, the earliest years remaining open for audit and/or settlement in the Company's major taxing jurisdictions are as follows: United States – 2011; Canada – 2008; United Kingdom – 2012; and Malaysia – 2007.

Note J – Incentive Plans

Murphy utilizes cash-based and/or share-based incentive plans to supplement normal salaries as compensation for executive management and certain employees. For share-based awards that qualify for equity accounting, costs are recognized as an expense in the financial statements using a grant date fair value-based measurement method over the periods that the awards vest. For share-based awards that are required to be accounted for under liability accounting rules, costs are recognized as expense using a fair value-based measurement method over the vesting period, but expense is adjusted as necessary through the date the award value is finally determined. Total expense for liability awards is ultimately adjusted to the final intrinsic value for the award.

In 2012, the Company's shareholders approved replacement of the 2007 Annual Incentive Plan (2007 Annual Plan) and the 2007 Long-Term Incentive Plan (2007 Long-Term Plan) with the 2012 Annual Incentive Plan (2012 Annual Plan) and 2012 Long-Term Incentive Plan (2012 Long-Term Plan), respectively. All awards to employees on or after May 9, 2012 have been made under the respective 2012 plans.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

The 2012 Annual Plan and the 2007 Annual Plan authorize the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and certain other employees. Cash awards under the 2012 Annual Plan and 2007 Annual Plan are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee. The 2012 Long-Term Plan and the 2007 Long-Term Plan authorize the Committee to make grants of the Company's Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2012 Long-Term Plan expires in 2022. A total of 8,700,000 shares are issuable during the life of the 2012 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding; allowed shares not granted may be granted in future years. Based on awards made to date, approximately 5,481,000 shares remained available for grant under the 2012 Long-Term Plan at December 31, 2014. The Company also has a 2013 Stock Plan for Non-Employee Directors (Director Plan) that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors.

Amounts recognized in the financial statements with respect to share-based plans are shown in the following table.

(Thousands of dollars)	2014	2013	2012
Compensation charged against income before income tax benefit	$ 53,157	66,976	46,694
Related income tax benefit recognized in income	15,604	19,321	14,443

As of December 31, 2014, there was $46,024,000 in compensation costs to be expensed over approximately the next two years related to unvested share-based compensation arrangements granted by the Company. Beginning January 1, 2014, employees will receive net shares, after applicable statutory withholding taxes, upon each stock option exercise. Cash received from options exercised under all share-based payment arrangements for the years ended December 31, 2013 and 2012 was $2,395,000 and $10,375,000, respectively. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were $5,364,000, $7,435,000 and $5,920,000 for the years ended December 31, 2014, 2013 and 2012, respectively.

Share-Settled Awards

STOCK OPTIONS – The Committee fixes the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixes the option term at no more than seven years from such date. Each option granted to date under the 2012 Long-Term Plan and the 2007 Long-Term Plan has been nonqualified, with a term of seven years and an option price equal to FMV at date of grant. Under the 2012 Long-Term Plan and the 2007 Long-Term Plan, one-half of each grant is generally exercisable after two years and the remainder after three years. For stock options, the number of shares issued upon exercise is reduced for settlement of applicable statutory income tax withholdings owed by the grantee.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

The fair value of each option award is estimated on the date of grant using the Black-Scholes pricing model based on the assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's stock and implied volatility on publicly traded at-the-money options on the Company's stock. The Company estimates the expected term of the options granted based on historical option exercise patterns and considers certain groups of employees exhibiting different behavior. The risk-free interest rate for periods within the expected term of the option is based on the U.S. Treasury yield curve in effect at the time of grant.

	2014	2013	2012
Fair value per option grant	$12.84	$15.81 – $20.62	$12.37 – $17.74
Assumptions			
Dividend yield	2.00%	2.10% – 2.30%	1.80% – 2.27%
Expected volatility	29.00%	34.00% – 36.00%	39.00% – 39.62%
Risk-free interest rate	1.62%	0.96% – 2.00%	0.55% – 0.77%
Expected life	5.35 yrs.	5.25 yrs. – 6.50 yrs.	4.00 yrs. – 5.20 yrs.

Changes in stock options outstanding during the last three years are presented in the following table.

	Number of Shares	Average Exercise Price
Outstanding at December 31, 2011	5,434,228	$ 55.17
Granted at FMV	1,870,500	57.96
Exercised	(823,855)	38.37
Forfeited	(573,514)	60.43
Outstanding at December 31, 2012	5,907,359	55.17
Granted at FMV	1,320,176	55.26
Exercised	(1,335,355)	45.84
Forfeited	(228,576)	58.01
Surrendered in connection with separation of Murphy USA Inc.	(272,936)	55.99
Murphy USA Inc. spin-off adjustment	615,917	52.09
Outstanding at December 31, 2013	6,006,585	56.80
Granted at FMV	772,900	55.82
Exercised	(862,407)	49.27

Forfeited	(314,828)	54.53
Outstanding at December 31, 2014	5,602,250	57.95
Exercisable at December 31, 2011	2,319,735	$ 51.14
Exercisable at December 31, 2012	2,474,636	54.43
Exercisable at December 31, 2013	2,435,322	51.79
Exercisable at December 31, 2014	3,030,105	53.10

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Additional information about stock options outstanding at December 31, 2014 is shown below.

	Options Outstanding			Options Exercisable		
Range of Exercise Prices per Option	No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value	No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value
\$37.44 to \$39.02	444,524	2.4	\$ 5,533,247	356,103	1.9	\$ 4,516,795
\$43.88 to \$51.63	1,772,764	1.8	2,786,024	1,162,708	2.4	2,786,024
\$54.21 to \$63.46	3,384,962	4.0	–	1,511,294	2.1	–
	5,602,250	3.6	\$ 8,319,271	3,030,105	2.4	\$ 7,302,819

The total intrinsic value of options exercised during 2014, 2013 and 2012 was \$12,003,000, \$25,284,000 and \$17,197,000, respectively. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company's Common stock.

In February 2013, the Committee reduced the exercise price of all outstanding stock options by \$2.50 per share to reflect the impact of the special dividend of the same amount paid in December 2012. The exercise prices in the preceding tables beginning in 2013 reflect this \$2.50 reduction in exercise price approved in 2013. The income statement effect of this reduced exercise price was an expense of \$6,454,000 in 2013.

In order to preserve the economic value of unexercised stock options following the spin-off of Murphy USA Inc. on August 30, 2013, the number of outstanding stock options was increased by 10.7% and the exercise price of stock options was reduced by 10.7%. The number of options and the exercise prices in the preceding tables reflect these adjustments related to the MUSA spin-off. There was no immediate impact on the expense for stock options recognized in 2013 related to this exercise price adjustment.

PERFORMANCE-BASED RESTRICTED STOCK UNITS – Performance-based restricted stock units (PRSUS) to be settled in Common shares were granted in each of the last three years under the 2012 Long-Term Plan or the 2007 Long-Term Plan. Each grant will vest if the Company achieves specific performance objectives at the end of the designated performance period. Additional shares may be awarded if performance objectives are exceeded. If performance goals are not met, PRSUS will not vest, but recognized compensation cost associated with the stock award would not be reversed. For past awards, the performance conditions were based on the Company's total shareholder return over the performance period compared to an industry peer group of companies. During the performance period, PRSUS are subject to transfer restrictions and are subject to forfeiture if a grantee terminates for reasons other than retirement, disability or death. Termination for these three reasons will lead to a pro rata award of amounts earned. No dividends are paid or voting rights exist on awards of PRSUS prior to their settlement.

Upon the separation of Murphy USA Inc. on August 30, 2013, adjustments to outstanding PRSUS were made to the number of units outstanding to preserve the economic value of these awards.

Changes in PRSUS outstanding for each of the last three years are presented in the following table.

(Number of share units)	2014	2013	2012
Outstanding at beginning of year	1,560,292	1,426,238	1,174,492
Granted	464,300	521,776	653,355
Awarded	(473,186)	(380,150)	(260,175)
Forfeited	(154,366)	(39,573)	(141,434)
Surrendered in connection with separation of Murphy USA Inc.	–	(116,568)	–
Murphy USA Inc. spin-off adjustment	–	148,569	–
Outstanding at end of year	1,397,040	1,560,292	1,426,238

The fair value of the equity-settled performance-based awards granted in each year was estimated on the date of grant using a Monte Carlo valuation model. Expected volatility was based on daily historical volatility of the Company's stock price compared to a peer group average over a three-year period. The risk-free interest rate is based on the yield curve of three-year U.S. Treasury bonds and the stock beta was calculated using three years of historical averages of daily stock data for Murphy and the peer group. The assumptions used in the valuation of the performance awards granted in 2014, 2013 and 2012 are presented in the following table.

	2014	2013	2012
Fair value per share at grant date	\$33.90 – \$51.30	\$39.50 – \$68.01	\$54.90 – \$63.64
Assumptions			
Expected volatility	29.00%	31.00% – 32.00%	37.00%
Risk-free interest rate	0.65%	0.41% – 0.62%	0.30%
Stock beta	0.843	0.907 – 0.908	0.913
Expected life	3.0 yrs.	3.0 yrs.	3.0 yrs.

TIME-LAPSE RESTRICTED STOCK UNITS – Time-lapsed restricted stock units (TSUS) have been granted to the Company's Non-Employee Directors under the Directors Plan and, beginning in 2014, to certain employees under the 2012 Long-Term Plan. These awards vest on the third anniversary of the date of grant. The fair value of these awards was estimated based on the market value of the Company's stock on the date of grant, which were \$55.20 to \$60.85 per share in 2014, \$60.30 to \$69.67 per share in 2013, and \$59.33 per share in 2012. To retain economic value at the time of spin-off of Murphy USA Inc., the number of TSUS was increased by 10.7% for each unit outstanding on August 30, 2013.

Changes in TSUS outstanding for each of the last three years are presented in the following table.

(Number of share units)	2014	2013	2012
Outstanding at beginning of year	112,881	98,477	116,724
Granted	278,892	38,184	42,256
Vested and issued	(54,884)	(34,696)	(44,980)
Forfeited	(15,100)	–	(15,523)
Murphy USA Inc. spin-off adjustment	–	10,916	–
Outstanding at end of year	321,789	112,881	98,477

EMPLOYEE STOCK PURCHASE PLAN (ESPP) – The Company has an ESPP under which the Company's Common stock can be purchased by eligible U.S. and Canadian employees. Each quarter, an eligible employee may elect to withhold up to 10% of his or her salary to purchase shares of the Company's stock at the end of the quarter at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP will terminate on the earlier of the date that employees have purchased all 980,000 authorized shares or June 30, 2017. Employee stock purchases under the ESPP were 6,739 shares at an average price of $56.22 per share in 2014, 16,020 shares at an average price of $54.14 per share in 2013 and 24,418 shares at an average price of $48.54 per share in 2012. At December 31, 2014, 280,202 shares remained available for sale under the ESPP. Compensation costs related to the ESPP are estimated based on the value of the 10% discount and the fair value of the option that provides for the refund of participant withholdings, and such expenses were $55,000 in 2014, $143,000 in 2013 and $272,000 in 2012. The fair value per share issued under the ESPP was approximately $6.49, $6.72 and $7.30 for the years ended December 31, 2014, 2013 and 2012, respectively.

Cash-Settled Awards

The Company has granted stock-based incentive awards to be settled in cash to certain employees in the form of Stock Appreciation Rights (SAR), Performance-based restricted stock units (PRSUC), Time-based restricted stock units (TRSUC) and Phantom units.

SAR awards have terms similar to stock options, PRSUC terms are similar to other performance-based restricted stock awards and TRSUC and Phantom units are generally settled on the third anniversary of the date of grant. Each award granted is settled, net of applicable income tax withholdings, in cash rather than with Common shares. Total expense recorded in the Consolidated Statements of Income for all cash-settled stock-based awards was $9,667,000 in 2014, $9,436,000 in 2013 and $552,000 in 2012.

Upon the separation of Murphy USA Inc. on August 30, 2013, adjustments to outstanding PRSUC were made to the number of units outstanding to preserve the economic value of these awards.

The Committee also administers the Company's incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and certain other employees. These cash awards are generally determinable based on the Company achieving specific financial and/or operational objectives. Compensation expense of $38,000,000, $53,250,000 and $32,417,000 was recorded in 2014, 2013 and 2012, respectively, for these plans.

Note K – Employee and Retiree Benefit Plans

PENSION AND OTHER POSTRETIREMENT PLANS – The Company has defined benefit pension plans that are principally noncontributory and cover most full-time employees. All pension plans are funded except for the U.S. and Canadian nonqualified supplemental plans and the U.S. directors' plan. All U.S. tax qualified plans meet the funding requirements of federal laws and regulations. Contributions to foreign plans are based on local laws and tax regulations. The Company also sponsors health care and life insurance benefit plans, which are not funded, that cover most retired U.S. employees. The health care benefits are contributory; the life insurance benefits are noncontributory.

Effective with the spin-off of Murphy's former U.S. retail marketing operation, Murphy USA Inc. (MUSA), on August 30, 2013, significant modifications were made to the U.S. defined benefit pension plan. Certain Murphy employees' benefits under the U.S. plan were frozen at that time. No further benefit service will accrue for the affected employees, however, the plan will recognize future earnings after the spin-off. In addition, all previously unvested benefits became fully vested at the spin-off date. For those affected active employees of the Company, additional U.S. retirement plan benefits will accrue in future periods under a cash balance formula. Additionally, new hires of Murphy after the MUSA spin-off are not eligible to participate in the Company's postretirement health care and life insurance benefit plans. Upon the spin-off of MUSA, Murphy retained all vested pension defined benefit and other postretirement benefit obligations associated with current and former employees of this separated business. No additional benefit will accrue for any employees of MUSA under the Company's retirement plans after the spin-off date.

Generally accepted accounting principles require the Company to recognize the overfunded or underfunded status of its defined benefit plans as an asset or liability in its consolidated balance sheet and to recognize changes in that funded status between periods through comprehensive income.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2014 and 2013 and a statement of the funded status as of December 31, 2014 and 2013.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2014	2013	2014	2013
Change in benefit obligation				
Obligation at January 1	$ 707,254	721,531	107,001	124,134
Service cost	22,470	26,346	2,459	4,566
Interest cost	33,680	30,903	4,617	5,189
Plan amendments	–	1,989	–	–
Participant contributions	5	21	1,406	1,376
Actuarial loss (gain)	122,824	(9,876)	8,150	(8,324)
Medicare Part D subsidy	–	–	404	384
Exchange rate changes	(14,614)	1,852	(55)	(36)
Benefits paid	(35,044)	(38,745)	(5,486)	(5,211)
Special termination benefits	–	849	–	–
Curtailments	(11,023)	(26,463)	–	(15,077)
Obligation assumed by MUSA at separation	–	(1,153)	–	–
Obligation at December 31	825,552	707,254	118,496	107,001
Change in plan assets				
Fair value of plan assets at January 1	533,108	463,546	–	–
Actual return on plan assets	31,340	61,932	–	–
Employer contributions	47,279	46,726	3,676	3,451
Participant contributions	5	21	1,406	1,376
Medicare Part D subsidy	–	–	404	384
Exchange rate changes	(13,284)	1,594	–	–
Benefits paid	(35,044)	(38,745)	(5,486)	(5,211)
Other	(2,426)	(1,966)	–	–
Fair value of plan assets at December 31	560,978	533,108	–	–
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	7,899	10,254	–	–
Other accrued liabilities	(5,996)	(5,565)	(5,515)	(5,920)
Deferred credits and other liabilities	(252,237)	(158,589)	(112,981)	(101,081)
Liabilities associated with assets held for sale	(14,240)	(20,246)	–	–
	$ (264,574)	(174,146)	(118,496)	(107,001)

Funded status and net plan liability recognized
at December 31

The significant actuarial loss in 2014 for pension benefits was primarily due to a combination of a lower discount rate and new actuarial mortality assumptions adopted by the Society of Actuaries in 2014. The new mortality assumptions reflect the expectation of generally longer lives for U.S. participants based on the latest study by the Society of Actuaries.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

At December 31, 2014, amounts included in accumulated other comprehensive loss (AOCL), before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	$ (256,821)	(21,948)
Prior service (cost) credit	(2,456)	289
	$ (259,277)	(21,659)

Amounts included in AOCL at December 31, 2014 that are expected to be amortized into net periodic benefit expense during 2015 are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	$ (16,706)	(778)
Prior service (cost) credit	(854)	82
	$ (17,560)	(696)

The table that follows includes projected benefit obligations, accumulated benefit obligations and fair value of plan assets for plans where the accumulated benefit obligation exceeded the fair value of plan assets.

	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
(Thousands of dollars)	2014	2013	2014	2013	2014	2013
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	$ 658,618	571,217	597,918	520,610	533,165	502,308

Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	147,018	115,492	127,200	102,198	–	–
Unfunded other postretirement plans	118,496	107,001	118,496	107,001	–	–

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2014.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	2014	2013	2012	2014	2013	2012
Service cost	$ 22,470	26,346	23,500	2,459	4,566	3,958
Interest cost	33,680	30,903	29,869	4,617	5,189	5,174
Expected return on plan assets	(33,723)	(28,974)	(25,826)	–	–	–
Amortization of prior service cost (credit)	899	1,006	1,254	(82)	(143)	(173)
Amortization of transitional (asset) liability	(480)	(514)	(529)	–	8	8
Recognized actuarial loss	9,471	17,338	16,389	5	1,484	1,317
	32,317	46,105	44,657	6,999	11,104	10,284
Termination benefits expense	–	849	6,177	–	–	–
Curtailment expense (benefit)	–	1,365	–	–	(442)	–
Net periodic benefit expense	$ 32,317	48,319	50,834	6,999	10,662	10,284

Termination and curtailment expenses in 2013 primarily related to plan amendments made at the time of separation of Murphy USA Inc. The termination benefits expense in 2012 was primarily related to enhanced retirement benefits provided to a former executive officer.

The preceding tables in this note include the following amounts related to foreign benefit plans.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2014	2013	2014	2013
Benefit obligation at December 31	$ 222,497	211,799	648	541
Fair value of plan assets at December 31	202,305	188,575	–	–
Net plan liabilities recognized	20,192	23,224	648	541
Net periodic benefit expense	12,968	12,622	152	92

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2014 and 2013 and net periodic benefit expense for 2014 and 2013.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits December 31		Other Postretirement Benefits December 31		Pension Benefits Year		Other Postretirement Benefits Year	
	2014	2013	2014	2013	2014	2013	2014	2013
Discount rate	3.94%	4.78%	4.12%	4.91%	4.56%	4.23%	4.91%	4.18%
Expected return on plan assets	6.11%	6.24%	–	–	6.11%	6.24%	–	–
Rate of compensation increase	3.69%	4.14%	–	–	3.69%	4.12%	–	–

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

The discount rates used for determining the plan obligations and expense are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Expected compensation increases are based on anticipated future averages for the Company.

Benefit payments, reflecting expected future service as appropriate, which are expected to be paid in future years from the assets of the plans or by the Company are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
2015	$ 33,516	6,349
2016	34,212	6,573
2017	35,144	6,730
2018	36,439	6,943
2019	37,671	7,225
2020-2024	208,294	40,535

For purposes of measuring postretirement benefit obligations at December 31, 2014, the future annual rates of increase in the cost of health care were assumed to be 7.2% for 2015 decreasing each year to an ultimate rate of 4.5% in 2028 and thereafter.

Assumed health care cost trend rates have a significant effect on the expense and obligation reported for the postretirement benefit plan. A 1% change in assumed health care cost trend rates would have the following effects.

(Thousands of dollars)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2014	$ 1,190	(942)
	17,879	(14,456)

Effect on the health care component of the accumulated postretirement benefit
obligation at December 31, 2014

During 2014, the Company made contributions of $27,948,000 to its domestic defined benefit pension plans, $19,331,000 to its foreign defined benefit pension plans, $3,641,000 to its domestic postretirement benefits plan and $35,000 to its foreign postretirement benefits plan. The Company currently expects during 2015 to make contributions of $40,045,000 to its domestic defined benefit pension plans, $18,739,000 to its foreign defined benefit pension plans, $5,481,000 to its domestic postretirement benefits plan and $36,000 to its foreign postretirement benefits plan.

U.S. Health Care Reform – In March 2010, the United States Congress enacted a health care reform law. Along with other provisions, the law (a) eliminated the tax free status of federal subsidies to companies with qualified retiree prescription drug plans that are actuarially equivalent to Medicare Part D plans beginning in 2013; (b) imposes a 40% excise tax on high-cost health plans as defined in the law beginning in 2018; (c) eliminated lifetime or annual coverage limits and required coverage for preventative health services beginning in September 2010; and (d) imposed a fee of $2 (subsequently adjusted for inflation) for each person covered by a health insurance policy beginning in September 2010. The Company provides a health care benefit plan to eligible U.S. employees and most U.S. retired employees. The law did not significantly affect the Company’s consolidated financial statements as of December 31, 2014, 2013 and 2012 and for the years then ended. The Company continues to evaluate the various components of the law as guidance is issued and cannot predict with certainty all the ways it may impact the Company. However, based on information available to date, the Company currently believes that the health care reform law will not have a material effect on its financial condition, net income or cash flow in future periods.

Plan Investments – Murphy Oil Corporation maintains an Investment Policy Statement (Statement) that establishes investment standards related to its funded domestic qualified retirement plan. The Statement specifies that all assets will be held in a Trust sponsored by the Company, which is administrated by a trustee appointed by the Investment Committee (Committee). Members of the Committee are appointed by the Board of Directors. The Committee hires Investment Managers to invest trust assets within the guidelines established by the Committee as allowed by the Statement. The investment goals call for a portfolio of assets consisting of equity, fixed income and cash equivalent securities. The primary consideration for investments is the preservation of capital, and investment growth should exceed the rate of inflation. The Committee has directed the asset investment advisors of its benefit plans to maintain a portfolio consisting of both equity and fixed income securities. The Company believes that over time a balanced to slightly heavier weighting of the portfolio in equity securities compared to fixed income securities represents the most appropriate long-term mix for future investment return on assets held by domestic plans. The parameters for asset allocation call for the following minimum and maximum percentages: equity securities of between 40% and 70%; fixed income securities of between 30% and 60%; long/short equity of between 0% and 15%; and cash and equivalents of between 0% and 15%. The Committee is authorized to direct investments within these parameters. Equity investments may include common, preferred and convertible preferred stocks, emerging markets stocks and similar funds, and long/short equity funds. Long/short equity is a strategy invested in a portfolio of long stocks hedged with short sales of stocks and/or stock index options, with the combination of investment intended to produce equity-like returns with lower volatility over the long term. Generally no more than 10% of an Investment Manager's portfolio is to be held in equity securities of any one issuer, and equity securities should have a minimum market capitalization of $100 million. Equities held in the trust should be listed on the New York or American Stock Exchanges, principal U.S. regional exchanges, major foreign exchanges or quoted in significant over-the-counter markets. Equity or fixed income securities issued by the Company may not be held in the trust. Fixed income securities include maturities greater than one year to maturity. The fixed income portfolio should not exceed an average maturity of 11 years. The portfolio may include investment grade corporate bonds, issues of the U.S. government, its agencies and government sponsored entities, government agency issued collateralized mortgage backed securities, agency issued mortgage backed securities, municipal bonds, asset backed securities, commercial mortgage backed securities and international and emerging markets bond funds. The Committee routinely reviews the investment performance of Investment Managers.

For the U.K. retirement plan, trustees have been appointed by the wholly-owned subsidiary that sponsors the plan for U.K. employees. The trustees have hired an investment consultant to manage the assets of the plan within the parameters of the Investment Policy Implementation Document (Document). The objective of investments is to earn a reasonable return within the allocation strategy permitted in the Document while limiting the risk for the funded position of the plan. The Document specifies a strategy with an allocation goal of 60% equities and 40% bonds. The Document allows for ranges of equity investments from 27% to 98%, fixed income securities may range from 25% to 60%, and cash can be held for up to 5% of investments. Approximately one-half of the equity allocation is to be invested in U.K. securities and the remainder split between North American, European, Japanese and other Pacific Basin securities. A minimum of 95% of the fixed income allocation is to be invested in U.K. securities with up to 5% in international or high yield bonds. Tolerance ranges are specified in the Document within the general equity/bond allocation guidelines. Asset performance is compared to a benchmark return based on the allocation guidelines and is targeted to outperform the benchmark by 0.75% per annum over a rolling three-year period. Small working cash balances are permitted to facilitate daily management of payments and receipts within the plan. The trustees routinely review the investment performance of the plan.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

For the Canadian retirement plan, the wholly-owned subsidiary that sponsors the plan has a Statement of Investment Policies and Procedures (Policy) applicable to the plan assets. A pension committee appointed by the board of directors of the subsidiary oversees the plan, selects the investment advisors and routinely reviews performance of the asset portfolio. The Policy permits assets to be invested in various Canadian and foreign equity securities, various fixed income securities, real estate, natural resource properties or participation rights and cash. The objective for plan investments is to achieve a total rate of return equal to the long-term interest rate assumption used for the going-concern actuarial funding valuation. The normal allocation includes total equity securities of 60% with a range of 40% to 75% of total assets. Fixed income securities have a normal allocation of 35% with a range of 25% to 45%. Cash will normally have an allocation of 5% with a range of 0% to 15%. The Policy calls for diversification norms within the investment portfolios of both equity securities and fixed income securities.

The weighted average asset allocation for the Company’s funded pension benefit plans at December 31, 2014 and 2013 are presented in the following table.

	December 31,	
	2014	2013
Equity securities	66.6 %	68.4 %
Fixed income securities	32.5	30.7
Cash equivalents	0.9	0.9
	100.0 %	100.0 %

The Company’s weighted average expected return on plan assets was 6.11% in 2014 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a portfolio with investment characteristics similar to that maintained by the plans. The 6.11% expected return was based on an expected average future equity securities return of 7.72% and a fixed income securities return of 4.04% and is net of average expected investment expenses of 0.53%. Over the last 10 years, the return on funded retirement plan assets has averaged 6.93%.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

At December 31, 2014, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
(Thousands of dollars)	Fair Value at December 31, 2014	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Plans				
Equity securities:				
U.S. core equity	$ 67,863	67,863	–	–
U.S. small/midcap	33,709	33,709	–	–
Hedged funds and other alternative strategies	52,905	–	18,953	33,952
International commingled trust fund	75,702	–	75,702	–
Emerging market commingled equity fund	19,908	–	19,908	–
Fixed income securities:				
U.S. fixed income	80,577	–	80,577	–
International commingled trust fund	17,559	–	17,559	–
Emerging market mutual fund	8,069	–	8,069	–
Cash and equivalents	2,381	2,381	–	–
Total Domestic Plans	358,673	103,953	220,768	33,952
Foreign Plans				
Equity securities funds	106,694	–	106,694	–
Fixed income securities funds	66,435	–	66,435	–
Diversified pooled fund	27,813	–	27,813	–
Cash and equivalents	1,363	1,363	–	–
Total Foreign Plans	202,305	1,363	200,942	–
Total	$ 560,978	105,316	421,710	33,952

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

At December 31, 2013, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

(Thousands of dollars)	Fair Value at December 31, 2013	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Plans				
Equity securities:				
U.S. core equity	$ 89,255	89,255	–	–
U.S. small/midcap	37,149	37,149	–	–
Hedged funds and other alternative strategies	32,788	–	–	32,788
International commingled trust fund	77,041	–	77,041	–
Emerging market commingled equity fund	9,654	–	9,654	–
Fixed income securities:				
U.S. fixed income	72,240	–	72,240	–
International commingled trust fund	14,865	–	14,865	–
Emerging market mutual fund	8,549	–	8,549	–
Cash and equivalents	2,992	2,992	–	–
Total Domestic Plans	344,533	129,396	182,349	32,788
Foreign Plans				
Equity securities funds	99,085	–	99,085	–
Fixed income securities funds	57,030	–	57,030	–
Diversified pooled fund	30,800	–	30,800	–
Cash and equivalents	1,660	1,660	–	–
Total Foreign Plans	188,575	1,660	186,915	–
Total	$ 533,108	131,056	369,264	32,788

The definition of levels within the fair value hierarchy in the tables above is included in Note Q.

For domestic plans, U.S. core and small/midcap equity securities are valued based on daily market prices as quoted on national stock exchanges or in the over-the-counter market. Hedged funds and other alternative strategies funds consist of three investments. One of these investments is valued based on daily market prices as quoted on national stock exchanges, another investment is valued monthly based on net asset value and permits withdrawals semi-annually after a 90-day notice, and the third investment is also valued monthly based on net asset values and has a three year lock-up period and a 95-day notice following the lock-up period. International equities held in a commingled trust are valued monthly based on prices as quoted on various international stock exchanges. The emerging market commingled equity fund is valued monthly based on net asset value. These commingled equity funds can be withdrawn monthly and have a 10-day notice period. U.S. fixed income securities are valued daily based on bids for the same or similar securities or using net asset values. International fixed income securities held in a commingled trust are valued on a monthly basis using net asset values. The fixed income emerging market mutual fund is valued daily based on net asset value. For foreign plans, the equity securities funds are comprised of U.K. and foreign equity funds valued daily based on fund net asset values. Fixed income securities funds are U.K. securities valued daily at net asset values. The diversified pooled fund is valued daily at net asset value and contains a combination of Canadian and foreign equity securities, Canadian fixed income securities and cash.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

The effects of fair value measurements using significant unobservable inputs on changes in Level 3 plan assets are outlined below:

(Thousands of dollars)	Hedged Funds and Other Alternative Strategies
Total at December 31, 2012	$ 14,654
Actual return on plan assets:	
Relating to assets held at the reporting date	3,134
Relating to assets sold during the period	–
Purchases, sales and settlements	15,000
Total at December 31, 2013	32,788
Actual return on plan assets:	
Relating to assets held at the reporting date	1,164
Relating to assets sold during the period	–
Purchases, sales and settlements	–
Total at December 31, 2014	$ 33,952

THRIFT PLANS – Most full-time U.S. and U.K. employees of the Company may participate in thrift or similar savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee’s allotment based on years of participation in the plans, with a maximum match of 6%. Amounts charged to expense for these plans were $10,229,000 in 2014, $13,839,000 in 2013 and $12,594,000 in 2012.

Note L – Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS – Murphy uses derivative instruments to manage certain risks related to commodity prices, interest rates and foreign currency exchange rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company’s senior management. The Company does not hold any derivatives for speculative purposes and it does not use derivatives with leveraged or complex features. Derivative instruments are traded primarily with creditworthy major financial institutions or over national exchanges such as the New York Mercantile Exchange (NYMEX). The Company has a risk management control system to monitor commodity price risks and any derivatives obtained to manage a portion of such risks. For accounting purposes, the Company has not designated commodity and foreign currency derivative contracts as hedges, and therefore, it recognizes all gains and losses on these derivative contracts in its Consolidated Statements of Income. Certain interest rate derivative contracts were accounted for as hedges and the gain or loss associated with recording the fair value of these contracts was deferred in Accumulated Other Comprehensive Income (Loss) until the anticipated transactions occur.

Commodity Purchase Price Risks – The Company is subject to commodity price risk related to crude oil it produces and sells. During 2014, the Company had West Texas Intermediate (WTI) crude oil price swap financial contracts to hedge a portion of its Eagle Ford Shale production for 2014. Under these contracts, which matured monthly, the Company paid the average monthly price in effect and received the fixed contract prices. At December 31, 2014, $23,168,000 is included in accounts receivable for final settlement of 2014 contracts. There were no open WTI contracts at year-end 2014 with maturity dates in 2015 or thereafter.

Foreign Currency Exchange Risks – The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. At December 31, 2014 and 2013, short-term derivative instruments were outstanding in Canada for approximately $21,000,000 and $32,300,000, respectively, to manage the currency risk of U.S. dollar accounts receivable balances associated with sale of Canadian crude oil in both years and a U.S. dollar intercompany accounts receivable balance at year-end 2013. The fair values of open foreign currency derivative contracts were liabilities of $25,000 at December 31, 2014 and $26,000 at December 31, 2013.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

At December 31, 2014 and 2013, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

(Thousands of dollars)	December 31, 2014 Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value	December 31, 2013 Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Type of Derivative Contract								
Commodity	Accounts Receivable	$ 23,168	–	–	Accounts Receivable	$ 1,970	–	–
Foreign exchange	–	–	Accounts Payable	$ 25	–	–	Accounts Payable	$ 1,038

For the years ended December 31, 2014 and 2013, the gains and losses recognized in the Consolidated Statements of Income for derivative instruments not designated as hedging instruments are presented in the following table.

(Thousands of dollars)	Year Ended December 31, 2014 Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative	Year Ended December 31, 2013 Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative
Type of Derivative Contract				
Commodity	Sale and Other Operating Revenues	$ 17,887	Sale and Other Operating Revenues	$ 2,104
Commodity	–	–	Discontinued Operations	(1,604)

Foreign exchange	Interest and Other Income	4,226	Interest and Other Income	(5,162)
		$ 22,113		$ (4,662)

Interest Rate Risks – In 2011 the Company entered into a series of derivative contracts known as forward starting interest rate swaps to manage interest rate risk associated with $350,000,000 of notes that were sold in 2012. These interest rate swaps matured in May 2012. Under hedge accounting rules, the Company deferred a loss on these contracts to match the payment of interest on these notes through 2022. During 2014, 2013 and 2012, $2,963,000, $2,963,000 and $1,852,000, respectively, of the deferred loss on the interest rate swaps was charged to interest expense in the Consolidated Statements of Income. The remaining loss deferred on these matured contracts at December 31, 2014 was $21,852,000, which is recorded, net of income taxes of $7,648,000, in Accumulated Other Comprehensive Income (Loss) in the Consolidated Balance Sheet. The Company expects to charge approximately $2,963,000 of this deferred loss to income in the form of interest expense during 2015.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

CREDIT RISKS – The Company's primary credit risks are associated with trade accounts receivable, cash equivalents and derivative instruments. Trade receivables arise mainly from sales of oil and natural gas in the U.S., Canada and Malaysia, and cost sharing amounts of operating and capital costs billed to partners for oil and natural gas fields operated by Murphy. The credit history and financial condition of potential customers are reviewed before credit is extended, security is obtained when deemed appropriate based on a potential customer's financial condition, and routine follow-up evaluations are made. The combination of these evaluations and the large number of customers tends to limit the risk of credit concentration to an acceptable level. Cash equivalents are placed with several major financial institutions, which limit the Company's exposure to credit risk. The Company controls credit risk on derivatives through credit approvals and monitoring procedures and believes that such risks are minimal because counterparties to the majority of transactions are major financial institutions.

Note M – Stockholders' Equity

On December 3, 2012, the Company paid a special dividend of $2.50 per outstanding Common share to shareholders of record on November 16, 2012. This dividend totaled $486,141,000.

In October 2012, the Company announced authorization of a share buyback program of up to $1.0 billion. This share repurchase program was completed in early 2014. In 2014, the Company announced two share buyback programs. The first program announced on May 20, 2014 totaled $125 million and was completed in August 2014. The second and larger program totaling up to $500 million was announced on August 6, 2014 and is still open. No shares have been acquired through year-end 2014 under this $500 million program that expires in August 2015. Future share repurchases could be carried out by utilization of a number of different methods, including but not limited to, open market purchases, accelerated share repurchases and negotiated block purchases, and some of the repurchases may be effected through Rule 10b5-1 plans. The shares acquired under the various buyback programs are carried as Treasury Stock in the Consolidated Balance Sheet.

Note N – Earnings per Share

The following table reconciles the weighted-average shares outstanding for computation of basic and diluted income per Common share for each of the three years ended December 31, 2014. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	2014	2013	2012
Basic method	178,852,942	187,921,062	193,902,335
Dilutive stock options	1,218,042	1,350,336	766,402
Diluted method	180,070,984	189,271,398	194,668,737

The following table reflects certain options to purchase shares of common stock that were outstanding during the three years ended December 31, 2014, but were not included in the total of dilutive stock options above because the incremental shares from assumed conversion were antidilutive.

	2014	2013	2012
Antidilutive stock options excluded from diluted shares	1,893,364	1,026,900	3,329,689
Weighted average price of these options	$ 55.21	$ 54.54	$ 64.72

Note O – Other Financial Information

GAIN FROM FOREIGN CURRENCY TRANSACTIONS – Net gains from foreign currency transactions, including the effects of foreign currency contracts, included in the Consolidated Statements of Income were $40,596,000 in 2014, $73,732,000 in 2013 and $5,092,000 in 2012.

CASH FLOW DISCLOSURES – Cash income taxes paid were $573,799,000, $457,006,000 and $566,999,000 in 2014, 2013 and 2012, respectively. Interest paid, net of amounts capitalized, was $114,232,000, $60,501,000 and $9,501,000 in 2014, 2013 and 2012, respectively.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2014 as shown in the following table.

(Thousands of dollars)	2014	2013	2012
Accounts receivable	$ 175,820	224,281	(382,137)
Inventories	25,697	14,166	(94,907)
Prepaid expenses	6,575	195,013	(245,881)
Deferred income tax assets	6,884	15,510	(7,218)
Accounts payable and accrued liabilities	(54,785)	(176,543)	534,353
Current income tax liabilities	(163,920)	(6,098)	27,610
Net (increase) decrease in noncash operating working capital	$ (3,729)	266,329	(168,180)

Note P – Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheets at December 31, 2014 and December 31, 2013 and the changes during 2013 and 2014 are presented net of taxes in the following table.

(Thousands of dollars)	Foreign Currency Translation	Retirement and Postretirement Benefit Plan	Deferred Loss on Interest	Total1

	Gains (Losses)1	Adjustments1	Rate Derivative Hedges1	
Balance at December 31, 2012	$ 613,492	(186,539)	(18,052)	408,901
2013 components of other comprehensive income (loss):				
Before reclassifications to income	(240,300)	59,145	–	(181,155)
Reclassifications to income	(68,000) [2]	10,438 [3]	1,935 [4]	(55,627)
Net other comprehensive income (loss)	(308,300)	69,583	1,935	(236,782)
Balance at December 31, 2013	305,192	(116,956)	(16,117)	172,119
2014 components of other comprehensive income (loss):				
Before reclassifications to income	(271,491)	(79,403)	–	(350,894)
Reclassifications to income	–	6,607 [3]	1,913 [4]	8,520
Net other comprehensive income (loss)	(271,491)	(72,796)	1,913	(342,374)
Balance at December 31, 2014	$ 33,701	(189,752)	(14,204)	(170,255)

[1] All amounts are presented net of income taxes.

[2] Reclassification is included in income from discontinued operations, net of income taxes.

[3] Reclassifications before taxes of $18,570 and $9,813 are included in the computation of net periodic benefit expense in 2013 and 2014, respectively. Related income taxes of $8,132 and $3,206 are included in Income tax expense in 2013 and 2014, respectively.

[4] Reclassifications before taxes of $2,963 are included in Interest expense in both 2013 and 2014. Related income taxes of $1,028 and $1,050 are included in Income tax expense in 2013 and 2014, respectively.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note Q – Assets and Liabilities Measured at Fair Value

The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheet. The fair value hierarchy is based on the quality of inputs used to measure fair value, with Level 1 being the highest quality and Level 3 being the lowest quality. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

The fair value measurements for these assets and liabilities at December 31, 2014 and 2013 are presented in the following table.

		Fair Value Measurements at Reporting Date Using		
(Thousands of dollars)	Fair Value at December 31, 2014	Quoted Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Commodity derivative contracts	$ 23,168	–	23,168	–
Liabilities				
Nonqualified employee savings plan	$ (14,408)	(14,408)	–	–
Foreign currency exchange derivative contracts	(25)	–	(25)	–
Total	$ (14,433)	(14,408)	(25)	–

		Fair Value Measurements at Reporting Date Using		
(Thousands of dollars)	Fair Value at December 31, 2013	Quoted Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Commodity derivative contracts	$ 1,970	–	1,970	–
Liabilities				
Nonqualified employee savings plan	$ (13,267)	(13,267)	–	–

Foreign currency exchange derivative contracts	(1,038)	–	(1,038)	–
Total	$ (14,305)	(13,267)	(1,038)	–

The fair value of West Texas Intermediate (WTI) crude oil contracts in 2013 was based on active market quotes for WTI crude oil. The fair value of foreign exchange derivative contracts in each year was based on market quotes for similar contracts at the balance sheet date. The income effect of changes in fair value of crude oil derivative contracts is recorded in Sales and Other Operating Revenues in the Consolidated Statements of Income, while the effects of changes in fair value of foreign exchange derivative contracts is recorded in Interest and Other Income. The nonqualified employee savings plan is an unfunded savings plan through which participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of the nonqualified employee savings plan is recorded in Selling and General Expenses.

The Company offsets certain assets and liabilities related to derivative contracts when the legal right of offset exists. There were no offsetting positions recorded at December 31, 2014 and 2013.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2014 and 2013. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The carrying value of Canadian government securities is determined based on cost plus earned interest. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. The Company has off-balance sheet exposures relating to certain letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	At December 31,			
	2014		2013	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets (liabilities):				
Canadian government securities with maturities greater than 90 days at the date of acquisition	$ 461,313	462,056	374,842	375,623
Current and long-term debt	(3,001,626)	(2,774,065)	(2,962,812)	(2,822,827)

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note R – Commitments

The Company leases production and other facilities under operating leases. The most significant operating leases are associated with floating, production, storage and offloading facilities at the Kikeh oil field and a production facility at the West Patricia field. During each of the next five years, expected future rental payments under all operating leases are approximately $108,717,000 in 2015, $71,573,000 in 2016, $51,744,000 in 2017, $45,669,000 in 2018 and $37,062,000 in 2019. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $144,981,000 in 2014, $192,482,000 in 2013 and $178,292,000 in 2012. A lease of production equipment at the Kakap field offshore Sabah, Malaysia has been accounted for as a capital lease and is included in long-term debt discussed in Note G.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2014. These rigs will primarily be utilized for drilling operations in the Gulf of Mexico, onshore U.S. and Canada, and offshore Malaysia and Australia. Future commitments under these contracts, all of which expire by 2017, total $559,272,000. A significant portion of these costs are expected to be borne by other working interest owners as partners of the Company when the wells are drilled. These drilling costs are generally expected to be accounted for as capital expenditures as incurred during the contract periods.

The Company has operating, production handling and transportation service agreements for oil and/or natural gas operations in the U.S. and Western Canada. These agreements require minimum monthly or annual payments for processing and/or transportation charges through 2024. Future required minimum monthly payments for the next five years are $64,928,000 in 2015, $49,792,000 in 2016, $40,512,000 in 2017, $33,019,000 in 2018 and $16,763,000 in 2019. Under certain circumstances, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Total costs incurred under these service arrangements were $34,597,000 in 2014, $40,254,000 in 2013 and $19,733,000 in 2012.

In 2006, the Company committed to fund an educational assistance program known as the “El Dorado Promise.” Under this commitment, the Company will pay $5,000,000 per year for ten years through 2016 to provide scholarships for a specified amount of college expenses for eligible graduates of El Dorado High School in Arkansas. The first nine payments have been made through January 2015. The Company recorded a discounted liability of $38,700,000 in 2006 for this unconditional commitment. The liability was discounted at the Company’s 10-year borrowing rate and the discounted liability increases for accretion monthly with a corresponding charge to Selling and General Expenses in the Consolidated Statement of Income. Total accretion cost was $541,000 in 2014, $805,000 in 2013 and $1,063,000 in 2012.

Commitments for capital expenditures were approximately $1,423,139,000 at December 31, 2014, including $416,892,000 for field development and future work commitments in Malaysia, $378,989,000 for work in the Eagle Ford Shale, $279,395,000 for costs to develop deepwater Gulf of Mexico fields, and $86,894,000, $79,036,000, $52,400,000 and $43,764,000 for future work commitments in Namibia, Equatorial Guinea, Vietnam and Australia, respectively.

Note S – Contingencies

The Company's operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax increases and retroactive tax claims; royalty and revenue sharing increases; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and gas or mineral leases; restrictions on drilling and/or production; laws and regulations intended for the promotion of safety and the protection and/or remediation of the environment; governmental support for other forms of energy; and laws and regulations affecting the Company's relationships with employees, suppliers, customers, stockholders and others. Because governmental actions are often motivated by political considerations, may be taken without full consideration of their consequences, and may be taken in response to actions of other governments, it is not practical to attempt to predict the likelihood of such actions, the form the actions may take or the effect such actions may have on the Company.

ENVIRONMENTAL MATTERS – Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment. Violation of federal or state environmental laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not insured, subject the Company to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result.

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy's control. Under existing laws the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. Certain of these historical properties are in various stages of negotiation, investigation, and/or cleanup, and the Company is investigating the extent of any such liability and the availability of applicable defenses. The Company has retained certain liabilities related to environmental matters at formerly owned U.S. refineries that were sold in 2011. The Company also obtained insurance covering certain levels of environmental exposures related to past operations of these refineries. Murphy USA Inc. has retained any environmental exposure associated with Murphy's former U.S. marketing operations that were spun-off in August 2013. The Company believes costs related to these sites will not have a material adverse affect on Murphy's net income, financial condition or liquidity in a future period.

The U.S. Environmental Protection Agency (EPA) formerly considered the Company to be a Potentially Responsible Party (PRP) at one Superfund site. Based on evidence provided by the Company, the EPA has determined that the Company is no longer considered a PRP at this site. Accordingly, the Company has not recorded a liability for remedial costs at the Superfund site at December 31, 2014. The potential total cost to all parties to perform necessary remedial work at the site may be substantial. The Company believes that its share of the ultimate costs to remediate the Superfund site will be immaterial and will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

There is the possibility that environmental expenditures could be required at currently unidentified sites, and new or revised regulations could require additional expenditures at known sites. However, based on information currently available to the Company, the amount of future remediation costs incurred at known or currently unidentified sites is not expected to have a material adverse effect on the Company's future net income, cash flows or liquidity.

LEGAL MATTERS – 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 environmental and legal matters referred to in this note is not expected to have a material adverse effect on the Company's net income, financial condition or liquidity in a future period.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note T – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2014 is shown below.

(Number of shares outstanding)	2014	2013	2012
At beginning of year	183,406,513	190,641,317	193,723,208
Stock options exercised*	119,994	303,685	482,974
Restricted stock awards*	339,985	300,910	224,296
Employee stock purchase and thrift plans	6,739	16,020	78,389
Treasury shares purchased	(6,373,718)	(7,855,419)	(3,867,550)
At end of year	177,499,513	183,406,513	190,641,317

*Shares issued upon exercise of stock options and award of restricted stock are less than the amount reflected in Note J due to withholdings for statutory income taxes owed upon issuance of shares.

Note U – Subsequent Events

On January 29, 2015, the Company completed the sale of 10% of its various interests in oil and gas properties in Malaysia to Pertamina. Upon closing, the Company received cash proceeds of $417,200,000.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note V – Business Segments

Murphy's reportable segments are organized into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, Malaysia and all other countries. Each of these segments derives revenues primarily from the sale of crude oil and/or natural gas. The Company's management evaluates segment performance based on income from operations, excluding interest income and interest expense. Intersegment transfers of crude oil, natural gas and petroleum products are at market prices and intersegment services are recorded at cost.

The Company desires to sell its U.K. finished product terminal operations. The Company carries the assets and liabilities of this business as held for sale at December 31, 2014. The Company sold its retail marketing operations in the United Kingdom on September 30, 2014. The Company was unable to sell its Milford Haven, Wales refinery and it is in the process of decommissioning the facility at year-end 2014. At December 31, 2014 and 2013, assets and liabilities associated with U.K. refining and marketing operations were reported as held for sale in the consolidated balance sheet. These operations have been reported as discontinued operations for all periods presented in these consolidated financial statements.

The Company sold all of its oil and natural gas producing assets in the United Kingdom during the first half of 2013. The Company also completed the separation of its U.S. retail marketing business on August 30, 2013. Both of these operations have also been reported as discontinued operations for all periods presented in these consolidated financial statements.

The Company has several customers that purchase a significant portion of its oil and natural gas production. During 2014, sales to Shell Oil and affiliated companies and Phillips 66 and affiliated companies represented approximately 20% and 14%, respectively, of the Company's total sales revenue. During 2013, sales to Phillips 66 and affiliated companies and Shell Oil and its affiliates represented approximately 17% and 14%, respectively, of the Company's total sales revenue. In 2012, Shell Oil, BP and Petronas represented approximately 17%, 13% and 12%, respectively, of consolidated sales. Due to the quantity of active oil and natural gas purchasers in the markets where it produces hydrocarbons, the Company does not foresee any difficulty with selling its hydrocarbon production at fair market prices.

Information about business segments and geographic operations is reported in the following tables. For geographic purposes, revenues are attributed to the country in which the sale occurs. Corporate and other activities, including interest income, miscellaneous gains and losses, interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. As used in the table on the following page, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets, and goodwill and other intangible assets.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Segment Information	Exploration and Production				
(Millions of dollars)	United States	Canada	Malaysia	Other*	Total E&P
Year ended December 31, 2014					
Segment income (loss)	$ 387.1	156.5	896.2	(250.0)	1,189.8
Revenues from external customers	2,196.4	1,044.1	2,183.5	(1.3)	5,422.7
Interest income	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–
Income tax expense (benefit)	214.8	64.2	102.6	(95.9)	285.7
Significant noncash charges (credits)					
Depreciation, depletion and amortization	840.7	316.7	735.0	5.1	1,897.5
Accretion of asset retirement obligations	17.5	15.2	18.1	–	50.8
Amortization of undeveloped leases	50.1	19.4	–	4.9	74.4
Impairment of assets	14.3	37.0	–	–	51.3
Deferred and noncurrent income taxes	39.7	43.3	(235.1)	–	(152.1)
Additions to property, plant, equipment	2,028.7	445.9	818.0	10.7	3,303.3
Total assets at year-end	5,745.7	3,769.8	4,887.1	138.7	14,541.3
Year ended December 31, 2013					
Segment income (loss)	$ 435.4	180.8	786.4	(373.8)	1,028.8
Revenues from external customers	1,803.8	1,144.7	2,280.5	83.6	5,312.6
Interest income	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–
Income tax expense (benefit)	241.6	57.8	477.7	(120.8)	656.3
Significant noncash charges (credits)					
Depreciation, depletion and amortization	576.3	374.6	588.2	4.5	1,543.6
Accretion of asset retirement obligations	13.5	16.2	15.0	4.3	49.0
Amortization of undeveloped leases	30.3	21.0	–	15.6	66.9
Impairment of assets	–	21.6	–	–	21.6
Deferred and noncurrent income taxes	99.6	26.1	48.1	–	173.8
Additions to property, plant, equipment	1,785.9	334.5	1,323.4	64.8	3,508.6
Total assets at year-end	4,530.0	4,087.8	6,121.0	180.4	14,919.2
Year ended December 31, 2012					
Segment income (loss)	$ 168.0	208.1	894.2	(365.3)	905.0
Revenues from external customers	1,038.0	1,084.3	2,428.1	57.7	4,608.1
Interest income	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–
Income tax expense (benefit)	99.8	65.1	544.7	(104.6)	605.0
Significant noncash charges (credits)					
Depreciation, depletion and amortization	330.2	345.8	532.1	36.3	1,244.4

Accretion of asset retirement obligations	11.4	13.6	12.5	0.9	38.4
Amortization of undeveloped leases	71.6	29.3	–	28.9	129.8
Impairment of assets	–	–	–	200.0	200.0
Deferred and noncurrent income taxes	231.0	72.3	73.3	(1.5)	375.1
Additions to property, plant, equipment	1,615.9	887.2	1,426.7	4.0	3,933.8
Total assets at year-end	3,625.9	4,477.7	4,811.5	187.8	13,102.9

Geographic Information	Certain Long-Lived Assets at December 31					
(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Other*	Total
2014	$ 5,419.5	3,574.6	4,258.8	0.4	78.1	13,331.4
2013	4,267.9	3,834.9	5,301.7	0.4	76.6	13,481.5
2012	4,177.4	4,190.5	4,101.2	703.2	45.1	13,217.4

*Reclassified to conform to current presentation.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Segment Information (Continued)

(Millions of dollars)	Corporate and Other	Discontinued Operations	Consolidated Total
Year ended December 31, 2014			
Segment income (loss)	$ (164.8)	(119.4)	905.6
Revenues from external customers	53.4	–	5,476.1
Interest income	7.7	–	7.7
Interest expense, net of capitalization	115.8	–	115.8
Income tax expense (benefit)	(58.4)	–	227.3
Significant noncash charges (credits)			
Depreciation, depletion and amortization	8.7	–	1,906.2
Accretion of asset retirement obligations	–	–	50.8
Amortization of undeveloped leases	–	–	74.4
Impairment of assets	–	–	51.3
Deferred and noncurrent income taxes	(18.8)	–	(170.9)
Additions to property, plant, equipment	14.5	–	3,317.8
Total assets at year-end	1,773.9	427.1	16,742.3
Year ended December 31, 2013			
Segment income (loss)	$ (140.7)	235.4	1,123.5
Revenues from external customers	77.5	–	5,390.1
Interest income	3.9	–	3.9
Interest expense, net of capitalization	71.9	–	71.9
Income tax expense (benefit)	(71.7)	–	584.6
Significant noncash charges (credits)			
Depreciation, depletion and amortization	9.8	–	1,553.4
Accretion of asset retirement obligations	–	–	49.0
Amortization of undeveloped leases	–	–	66.9
Impairment of assets	–	–	21.6
Deferred and noncurrent income taxes	(15.7)	–	158.1
Additions to property, plant, equipment	15.5	8.1	3,532.2
Total assets at year-end	1,265.2	1,325.1	17,509.5
Year ended December 31, 2012			
Segment income (loss)	$ (98.5)	164.4	970.9
Revenues from external customers	11.5	–	4,619.6
Interest income	6.5	–	6.5
Interest expense, net of capitalization	14.9	–	14.9
Income tax expense (benefit)	(43.5)	–	561.5
Significant noncash charges (credits)			

Depreciation, depletion and amortization	8.7	–	1,253.1
Accretion of asset retirement obligations	–	–	38.4
Amortization of undeveloped leases	–	–	129.8
Impairment of assets	–	–	200.0
Deferred and noncurrent income taxes	(32.3)	–	342.8
Additions to property, plant, equipment	8.2	191.8	4,133.8
Total assets at year-end	1,009.6	3,410.1	17,522.6

Geographic Information	Revenues from External Customers for the Year				
(Millions of dollars)	United States	Canada	Malaysia	Other	Total
2014	$ 2,201.5	1,052.4	2,233.0	(10.8)	5,476.1
2013	1,798.5	1,150.2	2,337.5	103.9	5,390.1
2012	1,038.1	1,088.4	2,415.6	77.5	4,619.6

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

The following unaudited schedules are presented in accordance with required disclosures about Oil and Gas Producing Activities to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies. Additional background information follows concerning five of the schedules.

SCHEDULE 1 – SUMMARY OF PROVED CRUDE OIL AND SYNTHETIC OIL RESERVES

SCHEDULE 2 – SUMMARY OF PROVED NATURAL GAS LIQUIDS RESERVES

SCHEDULE 3 – SUMMARY OF PROVED NATURAL GAS RESERVES

Reserves of crude oil, synthetic oil, condensate, natural gas liquids and natural gas are estimated by the Company's or independent engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data, and commercially available technologies, to establish 'reasonable certainty' of economic producibility. As defined by the SEC, reasonable certainty of proved reserves describes a high degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses familiar industry-accepted methods for subsurface evaluations, including performance, volumetric, and analogue based studies. Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy's proved reserves estimates, and was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas, and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data, and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

Murphy includes synthetic crude oil from its 5% interest in the Syncrude project in Alberta, Canada in its proved crude oil reserves. This operation involves a process of mining tar sands and converting the raw bitumen into a pipeline-quality crude. The proved reserves associated with this project are estimated through a combination of core-hole drilling and realized process efficiencies. The high-density core-hole drilling, at a spacing of less than 500 meters (proved area), provides engineering and geologic data needed to estimate the volumes of tar sand in place and its associated bitumen content. The bitumen generally constitutes approximately 10% of the total bulk tar sand that is mined. The bitumen extraction process is fairly efficient and removes about 90% of the bitumen that is contained within the tar sand. The final step of the process converts the 8.4° API bitumen into 30°-34° API crude oil. A catalytic cracking process is used to crack the long hydrocarbon chains into shorter ones yielding a final crude oil that can be shipped via pipelines. The cracking process has an efficiency ranging from 85% to 90%. Overall, it takes approximately two metric tons of oil sand to produce one barrel of synthetic crude oil. All synthetic oil volumes reported as proved reserves in Schedule 1 are the final synthetic crude oil product.

The Company has included a schedule of proved reserves of natural gas liquids (NGL) in this Form 10-K report. In the prior year's report, certain NGL proved reserves and associated changes were included in crude oil proved reserves. Therefore, certain adjustments of crude oil proved reserves previously reported in the 2013 Form 10-K report have been made to separate the effects of NGL for prior-year activities.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

All proved reserves in Malaysia are associated with production sharing contracts for Blocks SK 309/311, K and H. Malaysia reserves include oil and gas to be received for both cost recovery and profit provisions under the contract. Liquids and natural gas proved reserves associated with the production sharing contracts in Malaysia totaled 94.6 million barrels and 635.6 billion cubic feet, respectively, at December 31, 2014. Approximately 54.7 billion cubic feet of natural gas proved reserves in Malaysia at December 31, 2014 relate to fields in Block K for which the Company expects to receive sale proceeds of approximately $0.24 per thousand cubic feet.

SCHEDULE 5 – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

Results of operations from exploration and production activities by geographic area are reported as if these activities were not part of an operation that also refines crude oil and sells refined products.

SCHEDULE 6 – STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

Generally accepted accounting principles require calculation of future net cash flows using a 10% annual discount factor, an unweighted average of oil and natural gas prices in effect at the beginning of each month of the year, and year-end costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

Schedule 6 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2014.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 1 – Summary of Proved Crude Oil and Synthetic Oil Reserves Based on Average Prices

for 2011 – 2014

	Crude & Synthetic Oil	Crude Oil						Synthetic Oil
(Millions of barrels)	Total	Total	United States	Canada	Malaysia	United Kingdom	Other	Canada
Proved developed and undeveloped crude oil / synthetic oil reserves:								
December 31, 2011	349.7	220.2	55.3	36.6	104.4	21.6	2.3	129.5
Revisions of previous estimates	2.3	7.6	13.0	(3.4)	(0.7)	0.3	(1.6)	(5.3)
Improved recovery	7.2	7.2	–	–	7.2	–	–	–
Extensions and discoveries	84.0	84.0	77.3	2.9	3.8	–	–	–
Purchases of properties	12.5	12.5	6.5	6.0	–	–	–	–
Production	(40.9)	(35.8)	(9.5)	(5.3)	(19.0)	(1.3)	(0.7)	(5.1)
December 31, 2012	414.8	295.7	142.6	36.8	95.7	20.6	–	119.1
Revisions of previous estimates	27.4	24.8	13.1	8.4	3.3	–	–	2.6
Improved recovery	27.4	27.4	–	–	27.4	–	–	–
Extensions and discoveries	69.6	69.6	52.4	0.2	17.0	–	–	–
Purchases of properties	(20.4)	(20.4)	–	–	–	(20.4)	–	–
Production	(47.6)	(42.9)	(16.6)	(6.7)	(19.4)	(0.2)	–	(4.7)
December 31, 2013	471.2	354.2	191.5	38.7	124.0	0.0	–	117.0
Revisions of previous estimates	(9.3)	(2.3)	(3.2)	2.7	(1.8)	–	–	(7.0)
Improved recovery	7.5	7.5	–	–	7.5	–	–	–
Extensions and discoveries	42.6	42.6	32.7	2.4	7.5	–	–	–
Purchases of properties	6.1	6.1	6.1	–	–	–	–	–
Sales of properties	(24.3)	(24.3)	(0.3)	(0.5)	(23.5)	–	–	–
Production	(52.0)	(47.6)	(21.9)	(5.9)	(19.8)	–	–	(4.4)
December 31, 2014	441.8	336.2	204.9	37.4	93.9	–	–	105.6
Proved developed crude oil / synthetic oil reserves:								
December 31, 2011	238.5	118.0	20.8	32.6	57.2	5.1	2.3	120.5
December 31, 2012	267.7	148.6	48.0	29.5	67.0	4.1	–	119.1
December 31, 2013	289.9	172.9	75.8	31.6	65.5	–	–	117.0
December 31, 2014	324.1	218.5	106.2	32.4	79.9	–	–	105.6

Proved undeveloped crude oil / synthetic oil reserves:								
December 31, 2011	111.2	102.2	34.5	4.0	47.2	16.5	–	9.0
December 31, 2012	147.1	147.1	94.6	7.3	28.7	16.5	–	–
December 31, 2013	181.3	181.3	115.7	7.1	58.5	–	–	–
December 31, 2014	117.7	117.7	98.7	5.0	14.0	–	–	–

Note:All crude oil and synthetic reserves included in the table above are from consolidated subsidiaries and proportionately consolidated joint ventures. The Company has no proved crude oil and synthetic oil reserves attributable to investees accounted for by the equity method.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 1 – Summary of Proved Crude Oil and Synthetic Oil Reserves Based on Average Prices

for 2011 – 2014 – Continued

2014 Comments for Proved Crude Oil and Synthetic Oil Reserves Changes

Revisions of previous estimates – The 2014 negative crude oil revision in the U.S. was primarily attributed to a new downspacing drilling strategy at the Eagle Ford Shale, which recognizes incrementally greater reserves as an Extension for 2014. The positive Canadian conventional oil reserves revision in 2014 was based on Hibernia well performance and stronger heavy oil prices during 2014. The negative synthetic oil revision in 2014 was based on a review of the recoverable bitumen area coupled with the impact of a lower oil price. The negative revision for crude oil reserves in Malaysia in 2014 was attributable to an updated decline curve analysis for the Kikeh field, partially offset by a benefit for performance associated with field ramp up at Kakap.

Improved recovery – This 2014 Malaysia crude oil proved reserves add was associated with favorable impacts for waterflood activities at the Kikeh, Siakap North and Sarawak oil fields.

Extensions and discoveries – In 2014, the U.S. added proved oil reserves primarily for substantial drilling activities in the Eagle Ford Shale. Canadian proved oil reserves adds in 2014 were associated with drilling activities in the Seal heavy oil area and at the Hibernia field. The crude oil proved reserves adds in 2014 in Malaysia were mostly for drilling activities at the Siakap North and Sarawak oil fields.

Purchases of properties – The proved crude oil reserves adds in the U.S. were due to acquisition of an interest in the Kodiak field in the Gulf of Mexico.

Sales of properties – The proved crude oil reserves reduction in Malaysia was associated with the late 2014 sale of 20% of the Company's oil and gas assets. A further 10% of Malaysia assets was sold in 2015 and the associated reserves reduction will be reflected in the 2015 reserves table.

2013 Comments for Proved Crude Oil and Synthetic Oil Reserves Changes

Revisions of previous estimates – The positive revision for proved crude oil reserves in 2013 in the U.S. was attributable to better well performance in the Eagle Ford Shale area in South Texas, plus minor adds to several fields in the Gulf of Mexico. The positive revision for conventional oil in Canada was caused by well performance at the Hibernia and Terra Nova fields. Synthetic oil revisions were positive primarily due to revised cost recovery factors for bitumen extraction following renegotiated royalty terms with the government. Positive revisions in Malaysia were primarily attributable to well performance at Kikeh.

Improved recovery – The positive effect from improved recovery in Malaysia was at the Kikeh field where waterflood has led to better than anticipated response in certain reservoirs.

Extensions and discoveries – The U.S. proved crude oil reserve additions were all in the Eagle Ford Shale where the Company has used reliable technology to add offset locations associated with well downspacing in certain areas. Proved oil adds in Canada were associated with extensions at Seal. Additions to oil reserves in Malaysia primarily related to four new oil fields offshore Sarawak which were put on production during the second half of 2013.

Sales of properties – The Company sold all its oil fields in the U.K. during the first half of 2013.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 1 – Summary of Proved Crude Oil and Synthetic Oil Reserves Based on Average Prices

for 2011 – 2014 – Continued

2012 Comments for Proved Crude Oil and Synthetic Oil Reserves Changes

Revisions of previous estimates – A positive proved crude oil reserves revision in 2012 in the U.S. was due to improved well performance in the Eagle Ford Shale and at the Medusa field in the Gulf of Mexico. Downward revisions for conventional oil in Canada related to a lower recovery assessment for certain heavy oil wells in the Seal area. Negative proved oil revisions for synthetic oil in Canada related to an entitlement change based on recent spending projections that increased royalties estimated to be paid to the government. Negative proved oil revisions in the Other category related to Republic of the Congo and arose due to a combination of poor well performance on existing wells, a well that went off production in 2012, and generally uneconomic remaining future production due to oil recovery projections.

Improved recovery – The improved recovery in 2012 in Malaysia was essentially caused by better waterflood response in certain Kikeh field reservoir sands.

Extensions and discoveries – The U.S. proved crude oil reserves added in 2012 were primarily in the Eagle Ford Shale and were based on use of reliable technology to recognize additional offset undeveloped locations with 80 acre downspacing in certain areas of the play. The oil reserves added in Canada mostly related to additional development drilling off the East Coast at Hibernia and Terra Nova. Malaysia reserves increases primarily arose due to development drilling at fields offshore Sarawak.

Purchases of properties – Proved crude oil reserves added from property acquisitions in 2012 were associated with interests added at the Front Runner and Thunder Hawk fields in the U.S. Gulf of Mexico and in the Seal heavy oil area of Western Canada.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 2 – Summary of Proved Natural Gas Liquids (NGL) Reserves Based on Average Prices

for 2011 – 2014

(Millions of barrels)	Total	United States	Canada	Malaysia
Proved developed and undeveloped NGL reserves:				
December 31, 2011	–	–	–	–
Revisions of previous estimates	0.3	–	–	0.3
Improved recovery	–	–	–	–
Extensions and discoveries	–	–	–	–
Production	(0.3)	–	–	(0.3)
December 31, 2012	–	–	–	–
Revisions of previous estimates	15.7	15.6	–	0.1
Improved recovery	–	–	–	–
Extensions and discoveries	10.0	8.7	0.1	1.2
Production	(1.3)	(1.1)	–	(0.2)
December 31, 2013	24.4	23.2	0.1	1.1
Revisions of previous estimates	5.1	5.0	–	0.1
Improved recovery	–	–	–	–
Extensions and discoveries	4.7	4.0	0.6	0.1
Sales of properties	(0.2)	–	–	(0.2)
Production	(3.4)	(3.1)	–	(0.3)
December 31, 2014	30.6	29.1	0.7	0.8
Proved developed NGL reserves:				
December 31, 2011	–	–	–	–
December 31, 2012	–	–	–	–
December 31, 2013	14.2	13.1	–	1.1
December 31, 2014	17.5	16.5	0.2	0.8
Proved undeveloped NGL reserves:				
December 31, 2011	–	–	–	–
December 31, 2012	–	–	–	–
December 31, 2013	10.2	10.1	0.1	–
December 31, 2014	13.1	12.6	0.5	–

Note:All NGL reserves included in the table above are from consolidated subsidiaries and proportionately consolidated joint ventures. The Company has no proved NGL reserves attributable to investees accounted for by the equity method.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 2 – Summary of Proved Natural Gas Liquids (NGL) Reserves Based on Average Prices

for 2011 – 2014 – Continued

2014 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates – The positive 2014 NGL proved reserves revision in the U.S. was primarily in the Eagle Ford Shale based on an overall review of oil and gas mix for this production area.

Extensions and discoveries – The 2014 proved NGL reserves add in the U.S. was primarily attributable to drilling activities in the Eagle Ford Shale. The proved reserves add for Canadian NGL in 2014 was primarily associated with the drilling program in the Tupper and Tupper West areas.

Sales of properties – The Company sold 20% of its oil and gas assets in Malaysia in late 2014. A further 10% of oil and gas assets was sold in Malaysia in January 2015 and the associated reserves reduction will be reflected in the 2015 reserves table.

2013 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates – The positive U.S. revision to NGL proved reserves in 2013 was primarily due to well productivity in the Eagle Ford Shale, plus initial recognition of proved reserves quantities for NGL.

Extensions and discoveries – The NGL proved reserves add in 2013 in the U.S. was primarily attributable to development drilling in the Eagle Ford Shale.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 3 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2011 – 2014

(Billions of cubic feet)	Total	United States	Canada	Malaysia	United Kingdom
Proved developed and undeveloped natural gas reserves:					
December 31, 2011	1,106.1	98.4	638.9	347.8	21.0
Revisions of previous estimates	20.2	16.5	(37.2)	41.4	(0.5)
Improved recovery	7.2	–	–	7.2	–
Extensions and discoveries	173.5	107.2	25.8	40.5	–
Purchases of properties	9.4	7.0	2.4	–	–
Production	(179.4)	(19.4)	(79.5)	(79.3)	(1.2)
December 31, 2012	1,137.0	209.7	550.4	357.6	19.3
Revisions of previous estimates	33.7	(38.6)	34.0	38.3	–
Improved recovery	3.2	–	–	3.2	–
Extensions and discoveries	153.4	33.3	42.5	77.6	–
Sales of properties	(19.0)	–	–	–	(19.0)
Production	(154.7)	(19.4)	(64.1)	(70.9)	(0.3)
December 31, 2013	1,153.6	185.0	562.8	405.8	–
Revisions of previous estimates	167.2	47.7	105.6	13.9	–
Improved recovery	7.0	–	–	7.0	–
Extensions and discoveries	696.8	24.1	231.5	441.2	–
Purchases of properties	5.5	5.5	–	–	–
Sales of properties	(162.6)	(3.7)	–	(158.9)	–
Production	(162.8)	(32.3)	(57.1)	(73.4)	–
December 31, 2014	1,704.7	226.3	842.8	635.6	–
Proved developed natural gas reserves:					
December 31, 2011	711.6	58.2	427.1	210.5	15.8
December 31, 2012	706.0	78.8	415.8	197.3	14.1
December 31, 2013	786.2	112.6	384.0	289.6	–
December 31, 2014	812.1	145.6	467.4	199.1	–
Proved undeveloped natural gas reserves:					
December 31, 2011	394.5	40.2	211.8	137.3	5.2
December 31, 2012	431.0	130.9	134.6	160.3	5.2
December 31, 2013	367.4	72.4	178.8	116.2	–
December 31, 2014	892.6	80.7	375.4	436.5	–

Note:All natural gas reserves included in the table above are from consolidated subsidiaries and proportionately consolidated joint ventures. The Company has no proved natural gas reserves attributable to investees accounted for by the equity method.

2014 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – The positive revision for U.S. proved reserves of natural gas in 2014 was primarily attributable to good well performance at the new Dalmatian field in the Gulf of Mexico, plus a reassessment of oil and gas production mix in the Eagle Ford Shale that increased natural gas and gas liquids reserves with a corresponding decline in crude oil proved reserves. The positive revision associated with Canada natural gas proved reserves in 2014 was based on better performance in the Tupper and Tupper West areas following a change in the completion process. The positive revision for proved natural gas reserves in Malaysia in 2014 was primarily due to well performance and a higher entitlement rate for fields offshore Sarawak.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 3 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2011 – 2014 – Continued

2014 Comments for Proved Natural Gas Reserves Changes – Continued

Extensions and discoveries – The proved reserves of natural gas added in the U.S. in 2014 was primarily associated with the development drilling program in the Eagle Ford Shale, while the add in Canada in 2014 was attributable to drilling in the Tupper and Tupper West areas in Western Canada. The proved natural gas reserves added in Malaysia in 2014 was mostly associated with approval and sanction of the plan for a floating liquefied natural gas development in Block H, offshore Sabah, during the just completed year.

Purchases of properties – The Company acquired an interest in the Kodiak field in the Gulf of Mexico in 2014, which added proved reserves of natural gas during the year.

Sales of properties – The Company sold its interests in South Louisiana gas fields in 2014, plus it sold a 20% interest in oil and gas assets in Malaysia late in the year. A further 10% of Malaysia assets was sold in 2015 and the associated reserves reduction will be reflected in the 2015 reserves table.

2013 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – The U.S. natural gas proved reserves revisions in 2013 were unfavorable due to converting gas liquids volumes within the gas stream to proved NGL reserves. Positive revisions in Canada were mostly attributable to better well performance in the Tupper West area. Malaysia had positive gas revisions principally due to better well performance at gas fields offshore Sarawak and positive revisions due to better overall well production at the Kikeh field.

Improved recovery – The reserves add in Malaysia was attributable to better waterflood response at the Kikeh field due to better overall well production.

Extensions and discoveries – U.S. proved reserves of gas had adds in the Eagle Ford Shale due to additional offsets based on use of reliable technology with narrower downspacing in certain areas. The gas reserve adds in Canada were at the Tupper West and Tupper areas primarily caused by drilling activities and recognition of offset undeveloped locations. Natural gas proved reserve were added in Malaysia primarily due to initial booking of reserves of associated gas at three oil fields offshore Sarawak.

Sales of properties – The Company sold all of its U.K. oil and gas fields in the first half of 2013.

2012 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – The positive proved natural gas reserves revisions in the U.S. during 2012 were primarily caused by better well performance for certain fields in the Gulf of Mexico and in the Eagle Ford Shale. The negative revision in Canada was mostly attributable to weaker natural gas prices that unfavorably affected economical recovery at certain wells in the Montney formation in Western Canada. A positive natural gas reserves revision in Malaysia was related to better well performance and favorable entitlement effects for gas operations offshore Sarawak.

Improved recovery – The improved recovery in 2012 in Malaysia was essentially caused by better waterflood response in certain Kikeh field reservoir sands.

Extensions and discoveries – U.S. natural gas proved reserves added were primarily in the Eagle Ford Shale due to recognition of additional offsets from expanded use of reliable technology with 80 acre downspacing in certain areas of the play, plus the initial booking of proved gas reserves for the Dalmatian field in the Gulf of Mexico. Natural gas reserves added in Canada were primarily associated with drilling performed in the Tupper area. Reserves added in Malaysia were principally associated with development drilling operations at Sarawak gas fields.

Purchases of properties – Natural gas reserves added in 2012 related to additional interests acquired during the year at the Front Runner and Thunder Hawk fields in the U.S. Gulf of Mexico and in the Seal area of Western Canada.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 4 – Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom1	Other2	Total
Year Ended December 31, 2014						
Property acquisition costs						
Unproved	$ 92.9	–	–	–	–	92.9
Proved	7.4	–	–	–	–	7.4
Total acquisition costs	100.3	–	–	–	–	100.3
Exploration costs3	160.0	1.7	6.3	–	262.1	430.1
Development costs3	1,934.7	413.8	926.6	–	7.6	3,282.7
Total costs incurred	2,195.0	415.5	932.9	–	269.7	3,813.1
Charged to expense						
Dry hole expense	92.1	–	47.4	–	130.5	270.0
Geophysical and other costs	37.7	1.7	1.3	–	128.5	169.2
Total charged to expense	129.8	1.7	48.7	–	259.0	439.2
Property additions	$ 2,065.2	413.8	884.2	–	10.7	3,373.9
Year Ended December 31, 2013						
Property acquisition costs						
Unproved	$ 32.4	–	–	–	3.2	35.6
Proved	13.2	–	–	–	–	13.2
Total acquisition costs	45.6	–	–	–	3.2	48.8
Exploration costs3	112.4	21.8	14.9	–	344.6	493.7
Development costs3	1,773.2	351.6	1,787.7 4	8.1	19.0	3,939.6
Total costs incurred	1,931.2	373.4	1,802.6	8.1	366.8	4,482.1
Charged to expense						
Dry hole expense	46.1	32.1	20.7	–	164.0	262.9
Geophysical and other costs	29.1	0.7	4.6	–	138.0	172.4
Total charged to expense	75.2	32.8	25.3	–	302.0	435.3
Property additions	$ 1,856.0	340.6	1,777.3	8.1	64.8	4,046.8
Year Ended December 31, 2012						
Property acquisition costs						
Unproved	$ 107.7	14.6	–	–	10.2	132.5
Proved	69.1	242.4	–	–	–	311.5
Total acquisition costs	176.8	257.0	–	–	10.2	444.0
Exploration costs3	174.5	57.0	68.8	(1.0)	148.7	448.0
Development costs3	1,352.7	664.5	1,433.7	46.6	24.2	3,521.7
Total costs incurred	1,704.0	978.5	1,502.5	45.6	183.1	4,413.7
Charged to expense						
Dry hole expense	32.3	8.0	26.1	(0.8)	115.5	181.1
Geophysical and other costs	19.6	2.5	1.1	(0.2)	46.0	69.0

Total charged to expense	51.9	10.5	27.2	(1.0)	161.5	250.1
Property additions	$ 1,652.1	968.0	1,475.3	46.6	21.6	4,163.6

[1] The Company has accounted for U.K. operations as discontinued operations due to the sale of these operations in the first half of 2013.
[2] Due to the shutdown of production operations in Republic of the Congo, the Company now includes the result of these operations in the Other exploration and production segment in the above table.
[3] Includes non-cash asset retirement costs as follows:

2014						
Exploration costs	$ –	–	–	–	–	–
Development costs	36.5	(32.1)	66.2	–	–	70.6
	$ 36.5	(32.1)	66.2	–	–	70.6
2013						
Exploration costs	$ –	0.2	–	–	–	0.2
Development costs	70.1	5.9	95.9	–	–	171.9
	$ 70.1	6.1	95.9	–	–	172.1
2012						
Exploration costs	$ (1.7)	0.1	–	–	–	(1.6)
Development costs	37.9	80.7	48.6	(11.5)	17.6	173.3
	$ 36.2	80.8	48.6	(11.5)	17.6	171.7

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 5 – Results of Operations for Oil and Gas Producing Activities1

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other2	Total
Year Ended December 31, 2014						
Revenues						–
Crude oil and natural gas liquids sales	$ 2,062.1	453.3	391.5	1,680.2	–	4,587.1
Natural gas sales	127.2	201.3	–	357.5	–	686.0
Total oil and gas revenues	2,189.3	654.6	391.5	2,037.7	–	5,273.1
Other operating revenues	7.1	(2.4)	0.4	145.8	(1.3)	149.6
Total revenues	2,196.4	652.2	391.9	2,183.5	(1.3)	5,422.7
Costs and expenses						
Lease operating expenses	345.5	160.3	233.8	350.3	–	1,089.9
Severance and ad valorem taxes	96.5	5.6	5.1	–	–	107.2
Exploration costs charged to expense	129.8	1.7	–	48.7	259.0	439.2
Undeveloped lease amortization	50.1	19.4	–	–	4.9	74.4
Depreciation, depletion and amortization	840.7	262.7	54.0	735.0	5.1	1,897.5
Accretion of asset retirement obligations	17.5	6.0	9.2	18.1	–	50.8
Impairment of assets	14.3	37.0	–	–	–	51.3
Selling and general expenses	95.2	26.7	0.9	15.7	73.5	212.0
Other expenses	4.9	1.0	–	16.9	2.1	24.9
Total costs and expenses	1,594.5	520.4	303.0	1,184.7	344.6	3,947.2
Results of operations before taxes	601.9	131.8	88.9	998.8	(345.9)	1,475.5
Income tax expense (benefit)	214.8	42.4	21.8	102.6	(95.9)	285.7
Results of operations	$ 387.1	89.4	67.1	896.2	(250.0)	1,189.8
Year Ended December 31, 2013						
Revenues						
Crude oil and natural gas liquids sales	$ 1,724.7	507.2	441.0	1,875.0	83.6	4,631.5
Natural gas sales	72.7	198.1	–	404.0	–	674.8
Total oil and gas revenues	1,797.4	705.3	441.0	2,279.0	83.6	5,306.3
Other operating revenues	6.4	(1.9)	0.3	1.5	–	6.3
Total revenues	1,803.8	703.4	441.3	2,280.5	83.6	5,312.6
Costs and expenses						
Lease operating expenses	273.6	180.5	223.4	384.4	191.0	1,252.9
Severance and ad valorem taxes	77.5	5.0	4.8	–	–	87.3

Exploration costs charged to expense	75.2	32.8	–	25.3	302.0	435.3
Undeveloped lease amortization	30.3	21.0	–	–	15.6	66.9
Depreciation, depletion and amortization	576.3	319.2	55.4	588.2	4.5	1,543.6
Accretion of asset retirement obligations	13.5	5.9	10.3	15.0	4.3	49.0
Impairment of assets	–	21.6	–	–	–	21.6
Selling and general expenses	80.4	25.3	0.9	3.5	60.8	170.9
Total costs and expenses	1,126.8	611.3	294.8	1,016.4	578.2	3,627.5
Results of operations before taxes	677.0	92.1	146.5	1,264.1	(494.6)	1,685.1
Income tax expense (benefit)	241.6	19.9	37.9	477.7	(120.8)	656.3
Results of operations	$ 435.4	72.2	108.6	786.4	(373.8)	1,028.8

[1] Results exclude corporate overhead, interest and discontinued operations.

[2] Due to the shutdown of production operations in Republic of the Congo, the Company now includes the results of these operations in the Other exploration and production segment in the above tables.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 5 – Results of Operations for Oil and Gas Producing Activities[1] – Continued

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other[2]	Total
Year Ended December 31, 2012						
Revenues						
Crude oil and natural gas liquids sales	$ 976.1	411.7	463.1	1,946.0	57.6	3,854.5
Natural gas sales	54.2	209.8	–	481.1	–	745.1
Total oil and gas revenues	1,030.3	621.5	463.1	2,427.1	57.6	4,599.6
Other operating revenues	7.7	(0.9)	0.6	1.0	0.1	8.5
Total revenues	1,038.0	620.6	463.7	2,428.1	57.7	4,608.1
Costs and expenses						
Lease operating expenses	225.4	163.7	219.0	422.7	48.4	1,079.2
Severance and ad valorem taxes	27.0	3.5	5.1	–	–	35.6
Exploration costs charged to expense	51.9	10.5	–	27.2	161.5	251.1
Undeveloped lease amortization	71.6	29.3	–	–	28.9	129.8
Depreciation, depletion and amortization	330.2	290.5	55.3	532.1	36.3	1,244.4
Accretion of asset retirement obligations	11.4	5.1	8.5	12.5	0.9	38.4
Impairment of assets	–	–	–	–	200.0	200.0
Selling and general expenses	52.7	19.7	0.9	(5.3)	51.6	119.6
Total costs and expenses	770.2	522.3	288.8	989.2	527.6	3,098.1
Results of operations before taxes	267.8	98.3	174.9	1,438.9	(469.9)	1,510.0
Income tax expense (benefit)	99.8	25.1	40.0	544.7	(104.6)	605.0
Results of operations	$ 168.0	73.2	134.9	894.2	(365.3)	905.0

[1] Results exclude corporate overhead, interest and discontinued operations.
[2] Due to the shutdown of production operations in Republic of the Congo, the Company now includes the results of these operations in the Other exploration and production segment in the above table.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 6 – Standardized Measure of Discounted Future Net Cash Flows Relating to

Proved Oil and Gas Reserves

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Total
December 31, 2014					
Future cash inflows	$ 20,767.4	16,257.0	11,909.7	–	48,934.1
Future development costs	(3,151.4)	(1,810.5)	(1,920.8)	–	(6,882.7)
Future production costs	(6,378.5)	(7,770.2)	(4,575.6)	–	(18,724.3)
Future income taxes	(2,930.1)	(1,389.6)	(1,249.9)	–	(5,569.6)
Future net cash flows	8,307.4	5,286.7	4,163.4	–	17,757.5
10% annual discount for estimated timing of cash flows	(3,729.1)	(2,595.3)	(1,527.9)	–	(7,852.3)
Standardized measure of discounted future net cash flows	$ 4,578.3	2,691.4	2,635.5	–	9,905.2
December 31, 2013					
Future cash inflows	$ 20,638.6	16,112.9	13,399.0	–	50,150.5
Future development costs	(3,833.9)	(1,882.3)	(1,445.3)	–	(7,161.5)
Future production costs	(5,244.7)	(7,073.0)	(4,490.4)	–	(16,808.1)
Future income taxes	(3,368.3)	(1,472.8)	(1,855.1)	–	(6,696.2)
Future net cash flows	8,191.7	5,684.8	5,608.2	–	19,484.7
10% annual discount for estimated timing of cash flows	(4,020.2)	(2,999.1)	(1,620.7)	–	(8,640.0)
Standardized measure of discounted future net cash flows	$ 4,171.5	2,685.7	3,987.5	–	10,844.7
December 31, 2012					
Future cash inflows	$ 15,547.5	15,511.6	10,354.9	2,395.2	43,809.2
Future development costs	(3,731.6)	(1,815.2)	(966.9)	(273.2)	(6,786.9)
Future production costs	(3,466.6)	(7,336.4)	(3,143.4)	(738.3)	(14,684.7)
Future income taxes	(2,527.6)	(1,714.9)	(1,675.9)	(872.7)	(6,791.1)
Future net cash flows	5,821.7	4,645.1	4,568.7	511.0	15,546.5
10% annual discount for estimated timing of cash flows	(2,862.1)	(2,876.5)	(1,322.9)	(372.2)	(7,433.7)
Standardized measure of discounted future net cash flows	$ 2,959.6	1,768.6	3,245.8	138.8	8,112.8

Schedule 6 continues on Page F-65.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 6 – Standardized Measure of Discounted Future Net Cash Flows Relating to

Proved Oil and Gas Reserves – Continued

Following are the principal sources of change in the standardized measure of discounted future net cash flows for the years shown.

(Millions of dollars)		2014	2013	2012
Net changes in prices and production costs	$	(2,697.8)	267.8	(2,461.1)
Net changes in development costs		(2,317.3)	(3,456.8)	(3,860.1)
Sales and transfers of oil and gas produced, net of production costs		(4,076.0)	(3,972.4)	(3,493.3)
Net change due to extensions and discoveries		3,251.6	4,608.9	4,466.3
Net change due to purchases and sales of proved reserves		(1,041.0)	(135.6)	347.4
Development costs incurred		3,169.3	3,326.8	3,299.0
Accretion of discount		1,462.5	1,109.3	1,153.5
Revisions of previous quantity estimates		518.9	1,646.0	728.1
Net change in income taxes		790.3	(662.1)	9.8
Net increase (decrease)		(939.5)	2,731.9	189.6
Standardized measure at January 1		10,844.7	8,112.8	7,923.2
Standardized measure at December 31	$	9,905.2	10,844.7	8,112.8

Schedule 7 – Capitalized Costs Relating to Oil and Gas Producing Activities

(Millions of dollars)		United States	Canada	Malaysia	Other*	Subtotal	Synthetic Oil – Canada	Total
December 31, 2014								
Unproved oil and gas properties	$	634.9	424.1	–	168.1	1,227.1	–	1,227.1
Proved oil and gas properties		7,810.9	4,515.4	6,917.7	737.8	19,981.8	1,386.9	21,368.7
Gross capitalized costs		8,445.8	4,939.5	6,917.7	905.9	21,208.9	1,386.9	22,595.8

Accumulated depreciation, depletion and amortization							
Unproved oil and gas properties	(171.6)	(245.6)	–	(96.6)	(513.8)	–	(513.8)
Proved oil and gas properties	(2,944.0)	(2,082.1)	(2,665.3)	(737.8)	(8,429.2)	(433.1)	(8,862.3)
Net capitalized costs	$ 5,330.2	2,611.8	4,252.4	71.5	12,265.9	953.8	13,219.7
December 31, 2013							
Unproved oil and gas properties	$ 723.6	475.9	233.5	165.0	1,598.0	–	1,598.0
Proved oil and gas properties	5,816.9	4,529.9	7,636.6	737.8	18,721.2	1,493.5	20,214.7
Gross capitalized costs	6,540.5	5,005.8	7,870.1	902.8	20,319.2	1,493.5	21,812.7
Accumulated depreciation, depletion and amortization							
Unproved oil and gas properties	(178.1)	(248.5)	–	(91.7)	(518.3)	–	(518.3)
Proved oil and gas properties	(2,171.1)	(2,006.8)	(2,576.4)	(737.8)	(7,492.1)	(417.6)	(7,909.7)
Net capitalized costs	$ 4,191.3	2,750.5	5,293.7	73.3	12,308.8	1,075.9	13,384.7

*Due to the shutdown of production operations in Republic of the Congo, the Company now includes the results of these operations in the Other exploration and production segment in the above table.

Note:Unproved oil and gas properties above include costs and associated accumulated amortization of properties that do not have proved reserves; these costs include mineral interests, uncompleted exploratory wells, and exploratory wells capitalized pending further evaluation.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED)

(Millions of dollars except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year Ended December 31, 2014					
Sales and other operating revenues	$ 1,281.2	1,357.9	1,431.0	1,218.8	5,288.9
Income from continuing operations before income taxes	334.2	304.6	396.5	217.0	1,252.3
Income from continuing operations	169.3	142.7	271.0	442.0	1,025.0
Net income	155.3	129.4	245.7	375.2	905.6
Income from continuing operations per Common share					
Basic	0.94	0.80	1.52	2.49	5.73
Diluted	0.93	0.79	1.51	2.48	5.69
Net income per Common share					
Basic	0.86	0.72	1.38	2.11	5.06
Diluted	0.85	0.72	1.37	2.10	5.03
Cash dividend per Common share	0.3125	0.3125	0.35	0.35	1.325
Market price of Common Stock*					
High	63.70	66.82	67.75	56.13	67.75
Low	55.68	59.61	56.18	44.39	44.39
Year Ended December 31, 2013					
Sales and other operating revenues	$ 1,298.9	1,315.6	1,366.5	1,331.7	5,312.7
Income from continuing operations before income taxes	360.0	454.2	463.7	194.8	1,472.7
Income from continuing operations	182.7	259.9	265.0	180.5	888.1
Net income	360.6	402.7	284.8	75.4	1,123.5
Income from continuing operations per Common share					
Basic	0.96	1.38	1.42	0.98	4.73
Diluted	0.95	1.37	1.41	0.96	4.69
Net income per Common share					
Basic	1.89	2.13	1.52	0.41	5.98
Diluted	1.88	2.12	1.51	0.40	5.94
Cash dividend per Common share	0.3125	0.3125	0.3125	0.3125	1.25
Market price of Common Stock*					

High	63.81	66.09	71.84	65.55	71.84
Low	59.33	59.98	59.80	59.93	59.33

*Prices are as quoted on the New York Stock Exchange.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SCHEDULE II – VALUATION ACCOUNTS AND RESERVES

(Millions of dollars)	Balance at January 1	Charged (Credited) to Expense	Deductions	Other*	Balance at December 31
2014					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	–	–	–	1.6
Deferred tax asset valuation allowance	633.7	37.7	–	(364.9)	306.5
2013					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 6.7	0.4	(0.4)	(5.1)	1.6
Deferred tax asset valuation allowance	524.0	115.4	–	(5.7)	633.7
2012					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 7.9	0.3	(1.5)	–	6.7
Deferred tax asset valuation allowance	445.8	78.2	–	–	524.0

*Amount in 2014 for deferred tax asset valuation allowance is primarily associated with final abandonment of certain foreign investments in 2014, essentially offsetting changes in deferred tax assets. Amounts in 2013 primarily arose due to separation of Murphy USA Inc. and presentation of U.K. downstream operations as assets held for sale.

GLOSSARY OF TERMS

3D seismic

three-dimensional images created by bouncing sound waves off underground rock formations that are used to determine the best places to drill for hydrocarbons

bitumen or oil sands

tar-like hydrocarbon-bearing substance that occurs naturally in certain areas at the Earth's surface or at relatively shallow depths and which can be recovered, processed and upgraded into a light, sweet synthetic crude oil

deepwater

offshore location in greater than 1,000 feet of water

downstream

refining and marketing operations

dry hole

an unsuccessful exploration well that is plugged and abandoned, with associated costs written off to expense

exploratory

wildcat and delineation, e.g., exploratory wells

hydrocarbons

organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products

synthetic oil

a light, sweet crude oil produced by upgrading bitumen recovered from oil sands

upstream

oil and natural gas exploration and production operations, including synthetic oil operation

wildcat

well drilled to target an untested or unproved geologic formation

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