MURPHY OIL CORP /DE
Form 10-K
February 28, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011

OR

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

Commission file number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**71-0361522**
(State or other jurisdiction of	**(I.R.S. Employer**

incorporation or organization)	**Identification Number)**
200 Peach Street, P.O. Box 7000,	
El Dorado, Arkansas	**71731-7000**
(Address of principal executive offices)	**(Zip Code)**

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

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

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

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

None

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter (as of June 30, 2011) $12,706,062,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2012 was 193,877,158.

Documents incorporated by reference:

Portions of the Registrant s definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 9, 2012 have been incorporated by reference in Part III herein.

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MURPHY OIL CORPORATION

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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with retail and wholesale gasoline marketing operations in the United States and refining and marketing operations in the United Kingdom. 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. Its operations are classified into two business activities: (1) Exploration and Production and (2) Refining and Marketing. For reporting purposes, Murphy s exploration and production activities are subdivided into six geographic segments, including the United States, Canada, Malaysia, the United Kingdom, Republic of the Congo and all other countries. Murphy s refining and marketing activities are subdivided into segments for the United States and the United Kingdom. Additionally, Corporate activities include interest income, interest expense, foreign exchange effects and administrative costs not allocated to the segments.

The information appearing in the 2011 Annual Report to Security Holders (2011 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 24 through 46, F-17 and F-18, F-46 through F-52 and F-54 of this Form 10-K report and on pages 5 and 6 of the 2011 Annual Report.

At December 31, 2011, Murphy had 8,610 employees, including 3,176 full-time and 5,434 part-time.

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.

During 2011, 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, Republic of the Congo, Indonesia, Suriname, Australia, Brunei and the Kurdistan region of Iraq by wholly owned Murphy Exploration & Production Company International (Murphy Expro International) and its subsidiaries, in Western Canada and offshore Eastern Canada by wholly owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries, and in the U.K. North Sea and the Atlantic Margin by wholly owned Murphy Petroleum Limited. Murphy s crude oil and natural gas liquids production in 2011 was in the United States, Canada, Malaysia, the United Kingdom and Republic of the Congo; its natural gas was produced and sold in the United States, Canada, Malaysia and the United Kingdom. MOCL owns a 5% undivided interest in Syncrude Canada Ltd. in northern Alberta, one of the world s largest producers of synthetic crude oil.

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Unless otherwise indicated, all references to the Company s oil and gas production volumes and proved oil and gas reserves are net to the Company s working interest excluding applicable royalties.

Murphy s worldwide crude oil, condensate and natural gas liquids production in 2011 averaged 103,160 barrels per day, a decrease of 19% compared to 2010. The decrease was primarily due to lower 2011 oil production at the Kikeh field, offshore Sabah Malaysia, where several wells were shut-in for a portion of the year for well work due to sand production issues. The Company s worldwide sales volume of natural gas averaged 457 million cubic feet (MMCF) per day in 2011, up 28% from 2010 levels. The higher natural gas sales volume in 2011 was primarily attributable to increased natural gas production in the Montney area of Western Canada, where the Company s Tupper West area commenced gas production in early 2011 and where further development operations led to higher gas production at Tupper, and at fields offshore Sarawak Malaysia. Total worldwide 2011 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 179,388 barrels per day, a decrease of 4% compared to 2010.

Total production in 2012 is currently expected to average about 200,000 barrels of oil equivalent per day. The projected production increase of approximately 11% in 2012 is primarily related to higher natural gas production at the Tupper West area in Western Canada due to continued drilling, higher oil production at Kikeh following the well work program and additional field development operations, and higher oil and gas volumes produced in the Eagle Ford Shale area of South Texas as the Company continues to ramp-up its drilling program in the area. These volumes are expected to more than offset production declines in 2012 at other producing fields.

United States

In the United States, Murphy primarily has production of oil and/or natural gas from fields in the deepwater Gulf of Mexico, in the Eagle Ford Shale area of South Texas and onshore in South Louisiana. The Company produced approximately 17,100 barrels of oil per day and 47 million cubic feet of natural gas per day in the U.S. in 2011. These amounts represented 17% of the Company s total worldwide oil and 10% of worldwide natural gas production volumes. During 2011, approximately 45% of total U.S. hydrocarbon production was produced at two operated Gulf of Mexico fields Thunder Hawk and Medusa. The Company holds a 60% interest at Medusa in Mississippi Canyon Blocks 538/582, which produced total daily oil and natural gas of about 6,000 barrels and 6 MMCF, respectively, in 2011. Production from Medusa is expected to continue to decline in 2012 and should average 4,300 barrels of oil and about 4 MMCF of natural gas on a daily basis. At December 31, 2011, the Medusa field had total proved oil and natural gas reserves of approximately 5.8 million barrels and 5.9 billion cubic feet, respectively. Murphy has a 37.5% working interest in the Thunder Hawk field in Mississippi Canyon Block 734. Oil and natural gas production at Thunder Hawk averaged about 3,800 barrels of oil per day and 4 MMCF per day in 2011. Production in 2012 at Thunder Hawk is expected to average approximately 3,200 barrels of oil per day and 3 MMCF per day. The lower 2012 production at Thunder Hawk is due to well decline and a delay in performing drilling operations caused by permitting issues following the Macondo incident in 2010. Proved oil and natural gas reserves at Thunder Hawk at year-end 2011 were 3.3 million barrels and 4.0 billion cubic feet, respectively.

The Company has acquired rights to significant acreage in South Texas in the Eagle Ford Shale unconventional oil and gas play. The Company has eight active drilling rigs in the Eagle Ford in early 2012, with plans to exit 2012 with ten to twelve rigs in operation. Current plans are to drill approximately 130 wells in the play in 2012. The Company is primarily concentrating drilling efforts in the areas of the Eagle Ford where oil is the primary hydrocarbon produced. Lower natural gas price realization has caused the Company s drilling in the gas-prone areas to be limited to acreage where drilling is necessary to retain leases. Totals for 2011 oil and natural gas production in the Eagle Ford area were approximately 3,200 barrels per day and 3.3 MMCF per day, respectively. Due to ongoing drilling and infrastructure development activities, 2012 production is expected to be approximately 12,000 barrels of oil per day and 20 billion cubic feet of natural gas per day. At December 31, 2011, the Company s proved reserves in the Eagle Ford Shale area totaled 35.7 million barrels of oil and 38.2 billion cubic feet of natural gas. Total proved U.S. oil and natural gas reserves at December 31, 2011 were 55.3 million barrels and 98.4 billion cubic feet, respectively.

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Subsequent to the Macondo incident in April 2010, the process for obtaining drilling and other operational permits in the Gulf of Mexico has been extended significantly. The changes to the permitting process, as well as operational procedures, are expected to continue to cause delays and add more expense associated with drilling operations in the Gulf of Mexico. Therefore, the Company anticipates that its production, and likely many other companies production, will be adversely affected in the Gulf of Mexico during 2012 and possibly beyond because of permitting delays. The Company is unable to predict to what extent these delays and additional processes will ultimately impact its operations in the Gulf of Mexico.

Canada

In Canada, the Company owns an interest in three significant non-operated assets the Hibernia and Terra Nova fields offshore Newfoundland in the Jeanne d Arc Basin and Syncrude Canada Ltd. in northern Alberta. In addition, the Company owns interests in one heavy oil area, two significant natural gas areas and light oil prospective acreage 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%. The joint agreement between owners of Terra Nova required a one-time redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests exist. The redetermination process was essentially completed in 2010 and the Company s working interest was reduced from 12.0% to 10.475% effective January 1, 2011. The Company had recorded cumulative expense of $102.1 million through 2010 based on the anticipated settlement of the working interest reduction. The Company made a settlement payment to certain Terra Nova partners in January 2011 to equalize the value of oil sold and costs incurred since about March 2005 related to the difference between the Company s 10.475% ultimate working interest and its original 12.0% interest. The final settlement paid was less than the Company s original estimate and, therefore, a credit of $5.4 million was recorded to income in 2011. Oil production in 2011 was about 6,100 barrels of oil per day at Hibernia and 3,100 barrels per day at Terra Nova. Hibernia production decreased slightly in 2011 due to lower gross production and a higher royalty rate, while Terra Nova experienced well downtime and the Company s working interest was reduced from 12.0% in 2010 to 10.475% in 2011. Oil production for 2012 at Hibernia and Terra Nova is anticipated to be approximately 5,700 barrels per day and 2,800 barrels per day, respectively. Production declines at both fields in 2012 due to anticipated downtime for extended maintenance. Total proved oil reserves at December 31, 2011 at Hibernia and Terra Nova were approximately 10.8 million barrels and 6.6 million barrels, respectively.

Murphy owns a 5% undivided interest in Syncrude Canada Ltd., a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets, which include three coking units, to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Production in 2011 was about 13,500 barrels of synthetic crude oil per day and is expected to average about 14,200 barrels per day in 2012. Total proved reserves for Syncrude at year-end 2011 were 129.5 million barrels.

Daily production in 2011 in the WCSB averaged about 7,300 barrels of mostly heavy oil and about 189 MMCF of natural gas. Through 2011, the Company has acquired approximately 156,000 net acres of mineral rights in the northeastern British Columbia Montney area, including Tupper and Tupper West. Natural gas production commenced at Tupper in December 2008, while Tupper West production started up in February 2011. Oil and natural gas daily production for 2012 in Western Canada, excluding Syncrude, is expected to be about 10,200 barrels and 243 MMCF, respectively. The increase in oil production in 2012 is primarily due to an ongoing drilling program in the Seal heavy oil area. The increase in natural gas volumes in 2012 is primarily due to ramp-up of production at Tupper West associated with wells added from an ongoing drilling program. The initial production rates for Tupper West wells have been significantly better than anticipated at project sanction. However, natural gas prices in North America have weakened significantly in early 2012. Should natural gas prices in Canada continue to remain weak during 2012, the Company may elect to delay its development drilling program in the Tupper and Tupper West areas. This would lead to lower natural gas production volumes in the WCSB in 2012 and possibly beyond. Total Western Canada proved oil and natural gas reserves at December 31, 2011, excluding Syncrude, were 19.2 million barrels and 633.6 billion cubic feet, respectively.

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Through 2011, the Company has acquired approximately 146,000 net acres of land in Southern Alberta that is prospective for light oil. The Company began drilling operations on this acreage in early 2011. Several wells were expensed as dry holes during 2011. One well was on production test in early 2012. Additional wells are planned throughout 2012 to test various formations.

Malaysia

In Malaysia, the Company has majority interests in six separate production sharing contracts (PSCs). The Company serves as the operator of all these areas other than the Kakap development. The production sharing contracts cover approximately 3.74 million gross acres. Murphy has an 85% interest in discoveries made in two shallow-water blocks, SK 309 and SK 311, offshore Sarawak. In January 2010, Murphy relinquished all other acreage in Blocks SK 309 and SK 311, while retaining the acreage surrounding its producing oil and gas fields as well as areas surrounding its other discoveries, where development projects are ongoing or planned in the future. About 7,100 barrels of oil per day were produced in 2011 at Block SK 309/311, with 60% at the West Patricia field and the remainder mostly associated with gas liquids produced at other Sarawak fields. Oil production in 2012 at fields in Blocks SK 309/311 is anticipated to total about 6,000 barrels of oil per day. 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 allows for gross sales volumes of up to 250 MMCF per day through 2014, with an option to extend for seven years at 250 MMCF per day or for ten years at 350 MMCF per day. Total net natural gas sales volume offshore Sarawak was about 177 MMCF per day during 2011 (gross 242 MMCF per day). Sarawak net natural gas sales volumes are anticipated to be approximately 168 MMCF per day in 2012. Total proved reserves of oil and natural gas at December 31, 2011 for Blocks SK 309/311 were 4.7 million barrels and 253.9 billion cubic feet, respectively.

The Company made a major discovery at the Kikeh field in deepwater Block K, offshore Sabah, in 2002 and added another important discovery at Kakap in 2004. Several additional discoveries have been made in Block K at other areas. In 2006, the Company relinquished a portion of Block K and was granted a 60% interest in an extension of a portion of Block K. In 2011, the Company relinquished the remainder of Block K except for the discovered fields, including Kikeh and Kakap. Total gross acreage held by the Company in Block K as of December 31, 2011 was 1.02 million acres. Production volumes at Kikeh averaged 41,500 barrels of oil per day during 2011. Kikeh oil production declined significantly in 2011 compared to the prior year due to several wells being shut down for a portion of the year due to sand and fines produced with the oil. An extensive work program was undertaken and initial results have been successful and as expected. Oil production at Kikeh is anticipated to average approximately 49,400 barrels per day for 2012 as the development program there continues. In February 2007, the Company signed a Kikeh field natural gas sales contract with PETRONAS that calls for gross sales volumes of up to 120 MMCF per day through June 2012. Gas production at Kikeh is slated to continue thereafter until the earlier of lack of available commercial quantities of Kikeh associated gas reserves or expiry of the Block K production sharing contract. Natural gas production at Kikeh began in late 2008, and 2011 production totaled approximately 40 MMCF per day in 2011. Daily gas production in 2012 at Kikeh is expected to average about 49 MMCF per day. The Kakap field in Block K is operated by another company. This field is being jointly developed with the Gumusut field owned by others. Kakap development activities continued during 2011 and first production is anticipated in late 2012 or early 2013. The Siakap North oil discovery was made in 2009; the field will be a unitized development operated by Murphy. The field is presently under development as a tie-back to the Kikeh field and first oil production is currently anticipated in 2013. Total proved reserves booked in Block K as of year-end 2011 were 99.7 million barrels of oil and 93.9 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. In early 2008, the Company followed up Rotan with a discovery at Biris. In March 2008, the Company renewed the contract for Block H at a 60% interest while retaining 80% interest in the Rotan and Biris discoveries. In 2010 another natural gas discovery was made in

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Block H at Dolfin, and in early 2012, an additional gas discovery was made at Buluh. In 2011, the Company relinquished 30% of Block H, but retained all discovered fields. Total gross acreage held by the Company at year-end 2011 in Block H was 1.40 million acres. In early 2006, the Company added a 60% interest in a PSC covering Block P, which includes 1.05 million gross acres of the previously relinquished Block K area, offshore Sabah.

Murphy has a 75% interest in gas holding agreements for Kenarong and Pertang discoveries made in Block PM 311, located offshore peninsular Malaysia. Development options are being studied for these discoveries. Murphy relinquished its remaining interests in Block PM 311 and all of adjacent Block PM 312 in 2007.

United Kingdom

Murphy produces oil and natural gas in the United Kingdom sector of the North Sea. Total 2011 production in the U.K. amounted to about 2,400 barrels of oil per day and 4 MMCF of natural gas per day. Total 2012 daily production levels in the U.K. are anticipated to average about 3,000 barrels of oil and 5 MMCF of natural gas. In 2011, the Schiehallion partners approved a redevelopment plan comprising a subsea equipment upgrade with additional flowlines and new risers as well as a new floating production, storage and offloading vessel. The old vessel will be removed in 2013 and production is scheduled to resume through the new vessel in early 2016. Total proved reserves in the U.K. at December 31, 2011 were 21.6 million barrels of oil and 21.0 billion cubic feet of natural gas.

Republic of the Congo

The Company has interests in Production Sharing Agreements (PSA) covering two offshore blocks in Republic of the Congo Mer Profonde Sud (MPS) and Mer Profonde Nord (MPN). The Company s interests cover approximately 1.33 million gross acres with water depths ranging from 490 to 6,900 feet, and the Company serves as operator of both blocks. In 2005, Murphy made an oil discovery at Azurite Marine #1 in the southern block, MPS. The Company successfully followed up the Azurite discovery with other appraisal wells. First oil production occurred at the Azurite field in August 2009. Total oil production in 2011 averaged 5,000 barrels per day at Azurite for the Company s 50% interest. Anticipated production in 2012 is 3,700 barrels per day, with the decrease caused by natural decline at producing wells. Total proved oil reserves at the Azurite field as of December 31, 2011 were 2.3 million barrels. A significant revision was made in 2011 to reduce proved oil reserves at the Azurite field. The reserve revision was necessary based on the significantly lower oil recovery from producing wells. The reserve reduction led to an impairment charge of $368.6 million during 2011. In late 2010, the Company successfully negotiated an amendment to the PSA covering the MPS block. The new terms were officially approved in February 2011 and were effective retroactive to October 1, 2010. Essentially, the amendment revised terms of the PSA that allocates additional levels of crude oil production to the accounts of the Company and its non-government partners in future periods. The Company paid a bonus to Republic of the Congo in connection with the PSA amendment. A wildcat well drilled at Titane Marine in 2010 in the MPN block found accumulations of crude oil for which appraisal plans are pending. Development options are currently being studied. Other prospects in the MPN block are being evaluated and exploration wells are being planned for 2012.

Australia

The Company holds three exploration permits in Australia and serves as operator of each. A number of exploration wells will be drilled on the permits between 2012 and 2015. A 40% interest in Block AC/P36 in the Browse Basin offshore northwestern Australia covering 1.00 million gross acres was acquired in 2007 and one unsuccessful well has been drilled. The Company expects to increase its working interest in this block to 100% in 2012. Block WA-423P, also in the Browse Basin, was acquired in November 2008. The permit covers approximately 1.43 million gross acres with the Company holding a 40% working interest. Three-dimensional seismic has been acquired and a one year extension of the permit has been granted. Block NT/P80 in the Bonaparte Basin, offshore northwestern Australia, was acquired in June 2009 and covers approximately 1.21 million gross acres. Two-dimensional seismic was acquired and processed in 2011 on this block on which the Company s working interest is 40%.

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Indonesia

In May 2008, the Company entered into a production sharing contract in Indonesia, at a 100% interest, in the South Barito block in south Kalimantan on the island of Borneo. The block covers approximately 1.24 million gross acres. The agreement calls for relinquishment of 25% of acreage during 2012. The contract permits a six-year exploration term with an optional four-year extension. The work commitment calls for geophysical work, 2D seismic acquisition and processing, and two exploration wells. In November 2008, Murphy entered into a production sharing contract in the Semai II block offshore West Papua. The Company has a 28.3% interest in the block which covers about 835 thousand gross acres. The permit calls for a 3D seismic program and three exploration wells. The 3D seismic was acquired in 2010, while the first exploration well in the Semai II block was drilled in early 2011 and was unsuccessful. Multiple additional drilling prospects are currently being evaluated. 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 calls for seismic acquisition and processing, which the Company expects to begin in 2012. In November 2011, the Company acquired a 100% interest in a production sharing contract in the Semai IV block offshore West Papua. The concession includes 873 thousand gross acres. The agreement calls for work commitments of seismic acquisition and processing. Murphy is the operator of all the Indonesian concessions.

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. These blocks cover a significant portion of acreage formerly held by the Company in Malaysia Blocks L and M. The Malaysian Production Sharing Contracts covering Blocks L and M were terminated in early 2010. The CA-1 and CA-2 blocks cover 1.44 million and 1.49 million gross acres, respectively. The first two exploration wells in Block CA-2 and the initial well in Block CA-1 were drilled in 2011 and were unsuccessful.

Iraq

In late 2010, the Company finalized an agreement with the Kurdistan Regional Government (KRG) in Iraq to acquire an interest in the Central Dohuk block. The Company operates and holds a 50% interest in the block. The Central Dohuk block covers approximately 153 thousand gross acres and is located in the Dohuk area of the Kurdistan region in Iraq. The Company shot seismic in 2011 and plans an exploration well in 2012. In July 2011, the Company entered into an agreement with KRG to acquire a 20% non-operated interest in the Baranan block. Baranan covers approximately 178 thousand acres, and exploration plans call for seismic acquisition and the first exploration well in 2012.

Suriname

In June 2007, Murphy entered into a production sharing contract covering Block 37, offshore Suriname. Murphy operates this block and has a 100% working interest, subject to a potential reduction to 80% should the state oil company exercise its back-in option. Block 37 covers approximately 2.16 million gross acres and has water depths ranging from 160 to 1,000 feet. The contract provides for a six-year exploration period with two phases. Phase I has a four-year period that requires the acquisition of 3D seismic and the drilling of two wells. The 3D seismic was shot in late 2008 and early 2009, and interpretation of this data occurred in 2009. The first two exploration wells were drilled in late 2010 and early 2011 and were unsuccessful. Further exploration activities are presently being evaluated.

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 acres with water depths ranging from 1,000 to 3,000 meters. The 30-year contract is divided into an exploration period and one or more development and production periods, and may be extended with mutual agreement of Murphy and Staatsolie. There are three phases of the exploration period, with each divided into two-year terms, thereby allowing the Company to withdraw from the contract or enter into the next phase. Minimum work obligations vary during each exploration phase and may require either seismic data acquisition or drilling of an exploratory well. Staatsolie has the right to join in the development and production of each commercial field within the contract area with up to a 20% participation.

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 from Sterling Cameroon Limited (Sterling) via a farm-out agreement. Sterling retained a 50% non-operated interest in the block. The NTEM block, situated in the Douala Basin offshore Cameroon, encompasses 514 thousand gross acres, with water depths ranging from 300 to 1,900 meters. The concession is currently in force majeure, pending the resolution of a border dispute with neighboring Equatorial Guinea. When force majeure is lifted, there will be 15 months of the first renewal period remaining which can be extended for a further two years under the second renewal period option in the contract. Each of the renewal periods requires a minimum work obligation involving the drilling of exploratory wells.

Ecuador

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

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Proved Reserves

Total proved oil and natural gas reserves as of December 31, 2011 are presented in the following table.

	Proved Reserves		
	Oil	Synthetic Oil	Natural Gas
	(millions of barrels)		(billions of cubic feet)
Proved Developed Reserves:			
United States	20.8		58.2
Canada	32.6	120.5	427.1
Malaysia	57.2		210.5
United Kingdom	5.1		15.8
Republic of the Congo	2.3		
Total proved developed reserves	118.0	120.5	711.6
Proved Undeveloped Reserves:			
United States	34.5		40.2
Canada	4.0	9.0	211.8
Malaysia	47.2		137.3
United Kingdom	16.5		5.2
Republic of the Congo			
Total proved undeveloped reserves	102.2	9.0	394.5
Total proved reserves	220.2	129.5	1,106.1

Proved Undeveloped Reserves

Murphy s proved undeveloped reserves at December 31, 2011 increased 67.7 million barrels of oil equivalent (MMBOE) from a year earlier. Approximately 24.8 MMBOE of proved undeveloped reserves were converted to proved developed reserves during 2011. The majority of the proved undeveloped reserves migration to the proved developed category occurred at the Tupper and Tupper West gas areas, as these areas had active development work ongoing during the year. The conversion of non-proved reserves to newly reported proved undeveloped reserves occurred at several areas including, but not limited to, the Tupper, Tupper West and Eagle Ford Shale areas and the Kikeh field. During 2011, there were 11.7 MMBOE of positive revisions for proved undeveloped reserves. The majority of proved undeveloped reserves additions associated with revisions of previous estimates were the result of development drilling and well performance at the Kikeh field in Malaysia. The Company spent $422.1 million in 2011 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend about $2.1 billion in 2012, $1.4 billion in 2013 and $520 million in 2014 to move currently undeveloped proved reserves to the developed category. The higher level of spend in 2012 is caused by significant drilling in the year at several locations, including the Kikeh field, the Eagle Ford Shale and the Tupper West 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, 2011, proved reserves are included for several development projects that are ongoing, including natural gas developments at the Tupper West area in British Columbia and offshore Sarawak Malaysia, and an oil development at Kakap, offshore Sabah Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2011 were approximately 177 MMBOE, which is 33% of the Company s total proved reserves. Certain of these development projects have proved undeveloped reserves that will take more than five years to bring to production. Three such projects have significant levels of such proved undeveloped reserves. The Company operates a deepwater field in the Gulf of Mexico that has two undeveloped locations that exceed this five-year window. Total reserves associated with the two wells amount to less than 1% of the Company s total proved reserves at year-end 2011. The development of certain of this field s reserves stretches beyond five years due to limited well slots available on the production platform, thus making it necessary to wait for depletion of other wells prior to initiating further development of these two locations. The Kakap field oil development project has undeveloped proved reserves that make up less than 3% of the Company s total proved reserves at year-end 2011. This non-operated project will take longer than five years to develop due to long lead-time equipment required to complete the development process in the deep waters offshore Sabah Malaysia. The third project that will take more than five years to develop is offshore Malaysia and makes up approximately 1% of the Company s total proved reserves at year-end 2011. This project is an extension of the Sarawak natural gas project and should be on production in 2014 once current project production volumes decline.

Murphy Oil s Reserves Processes and Policies

The Company employs a General Manager of Corporate Reserves (General Manager) who is independent of the Company s oil and gas management. The General Manager reports to an Executive Vice President of Murphy Oil Corporation, who in turn reports directly to the President of the Company. The General Manager makes presentations to the Board of Directors periodically about the Company s reserves. The General 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 General 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 General Manager and qualified engineering staff from areas of the Company other than the area being audited. The General Manager may also utilize qualified independent reserves consultants to assist with the internal audits or to perform separate audits as considered appropriate. On occasion, the Company may use independent reserves consultants to determine its proved reserves reported in this Form 10-K. At December 31, 2011, the Company utilized Ryder Scott Company, L.P., an independent petroleum engineering company, to prepare estimated proved oil and natural gas reserves for the Eagle Ford Shale area in South Texas and the United Kingdom. The total estimated proved reserves prepared by Ryder Scott represented 16% of the Company s total proved oil reserves and 5% of the total proved natural gas reserves as of December 31, 2011. Ryder Scott s report, including a description of their engineer s technical qualifications for estimating reserves, is included as Exhibit 99.6 to this Annual Report on Form 10-K.

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

The Company s QREs maintain files containing pertinent data regarding each significant reservoir. Each file includes sufficient data to support the calculations or analogies used to develop the values. Examples of data included in the file, as appropriate, include: production histories; pertinent drilling and workover histories; bottom hole pressure data; volumetric, material balance, analogy or other pertinent reserve estimation data; production performance curves; narrative descriptions of the methods and logic used to determine reserves values; maps and logs; and a signed copy of the conclusion of the QRE stating, that in their opinion, the reserves have been calculated, reviewed, documented and reported in compliance with the regulations and guidelines contained in the reserves training manual. The Company s reserves are maintained in an industry recognized reservoir engineering software system, which has adequate access controls to avoid the possibility of improper manipulation of data.

When reserves calculations are completed by QREs and appropriately reviewed by RRCs and the General Manager, the conclusions are reviewed and discussed with the head of the Company s exploration and production business and other senior management as appropriate. The Company s Controller s department is responsible for preparing and filing reserves schedules within Form 10-K.

Murphy provides annual training to all company reserve estimators to ensure SEC requirements associated with reserve 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 reserve estimation.

Qualifications of General Manager of Corporate Reserves

The Company believes that it has qualified employees generating oil and gas reserves. Mr. Brad Gouge serves as General Manager of Corporate Reserves after joining the Company in mid-2008. Prior to that time, Mr. Gouge was Vice President at a major petroleum engineering consulting firm. He previously was a production and then reservoir engineer with a major integrated oil company. Mr. Gouge earned a Bachelors of Science degree in Petroleum Engineering from Texas A&M University and has attended numerous industry training courses. Mr. Gouge is a registered Professional Engineer in the state of Texas and is an instructor for a Society of Petroleum Engineers (SPE) Petroleum Reserves course. He is also co-author of two papers on estimating petroleum reserves which have been published by the SPE and serves on the SPE Oil and Gas Reserves Committee (ORGC), as well as, the Joint Committee on Reserves Evaluator Training (JCORET).

More information regarding Murphy s estimated quantities of proved oil and gas reserves for the last three years are presented by geographic area on pages F-48 and F-49 of this Form 10-K report. Murphy has not filed and is not required to file any estimates of its total proved oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated proved reserves of such properties are determined.

Crude oil, condensate and gas liquids production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the seven years ended December 31, 2011 are shown on page 5 of the 2011 Annual Report. In 2011, 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 33 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-46 through F-54 of this Form 10-K report.

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At December 31, 2011, 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	16	12	287	234	303	246
Gulf of Mexico	13	5	1,027	635	1,040	640
Alaska	4	1	2		6	1
Total United States	33	18	1,316	869	1,349	887
Canada Onshore, excluding oil sands	63	57	610	561	673	618
Offshore	94	8	117	10	211	18
Oil sands Syncrude	96	5	160	8	256	13
Total Canada	253	70	887	579	1,140	649
Malaysia	164	136	3,580	2,194	3,744	2,330
United Kingdom	34	4	17	2	51	6
Republic of the Congo	1		1,332	902	1,333	902
Suriname			2,959	2,959	2,959	2,959
Australia			3,640	1,456	3,640	1,456
Indonesia			4,174	3,218	4,174	3,218
Brunei			2,934	519	2,934	519
Cameroon			514	257	514	257
Iraq			331	112	331	112
Spain			36	6	36	6
Totals	485	228	21,720	13,073	22,205	13,301

Certain acreage held by the Company will expire in the next three years. Scheduled expirations in 2012 include 36 thousand net acres in Block PM 311 in Malaysia; and 188 thousand net acres in the United States. In 2013, 485 thousand net acres expire in Block H Malaysia; 629 thousand net acres expire in Block P Malaysia; 433 thousand acres in Block 37 in Suriname; and 116 thousand net acres expire in the United States. In 2014, 447 thousand net acres expire in South Barito Indonesia; 96 thousand net acres expire in Semai II Indonesia; 405 thousand net acres expire in Semai IV Indonesia; 619 thousand net acres expire in Wokam Indonesia; 448 thousand net acres expire in Blocks MPS and MPN in Republic of the Congo; and 134 thousand net acres expire in the United States.

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.

The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2011.

	Oil Wells		Gas Wells	
Country	Gross	Net	Gross	Net
United States	81	43	21	12
Canada	364	266	141	141
Malaysia	32	26	34	29
United Kingdom	36	3	23	2
Republic of the Congo	6	3		

Totals	519	341	219	184

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

	United States		Canada		Malaysia		United Kingdom		Other		Totals	
	Pro- ductive	Dry	Pro- ductive	Dry	Pro- ductive	Dry	Pro- ductive	Dry	Pro- ductive	Dry	Pro- ductive	Dry
2011												
Exploratory	**17.9**		**1.0**	**4.9**	**0.9**					**2.3**	**19.8**	**7.2**
Development	**14.3**	**0.8**	**117.5**	**6.0**	**12.8**				**0.5**		**145.1**	**6.8**
2010												
Exploratory	9.2				6.8	0.8		0.1	1.0	2.5	17.0	3.4
Development			87.0	5.0	23.6				2.5		113.1	5.0
2009												
Exploratory	1.3	0.6			5.6	1.6			0.5	0.7	7.4	2.9
Development	1.1		42.0	3.0	17.0		0.4		0.5		61.0	3.0

Murphy s drilling wells in progress at December 31, 2011 are shown below.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States	13	11.9	6	3.6	19	15.5
Canada			7	7.0	7	7.0
Malaysia			2	1.6	2	1.6
Totals	13	11.9	15	12.2	28	24.1

Refining and Marketing

The Company s refining and marketing businesses are located in the United States and United Kingdom. The U.S. business primarily consists of retail marketing of petroleum products through a large chain of motor refueling stations. Most of these stations are located on or near Walmart store sites, with the remaining stations located at other high traffic sites that are near major thoroughfares. The U.S. business entered the renewable fuels business and acquired an ethanol production facility in North Dakota during 2009, and also purchased an unfinished ethanol production facility in Texas in 2010 that was completed and began operations in 2011. Additionally, the U.S. operations include refined product terminals, and a crude oil and refined products trading business. The Company sold both its U.S. petroleum refineries at Meraux, Louisiana and Superior, Wisconsin, and certain associated marketing assets in 2011. The U.K. business primarily consists of operations that refine crude oil and other feedstocks into petroleum products such as gasoline and distillates, buy and sell crude oil and refined products, and transport and market petroleum products. The Company has announced its intention to sell its U.K. refining and marketing operations.

Murphy Oil USA, Inc. (MOUSA), a wholly owned subsidiary of Murphy Oil Corporation, markets refined products through a network of retail gasoline stations and unbranded wholesale customers in a 23-state area, primarily in the Southern and Midwestern United States. Murphy s retail stations are located in 23 states and are primarily located in the parking lots of Walmart Supercenters using the brand name Murphy USA®. The Company s stations also include stand-alone locations using the Murphy Express® brand. At December 31, 2011, the Company marketed products through 1,128 Murphy owned and operated stations. Of the Company stations, 1,003 are located on parking lots of Walmart Supercenters and 125 are stand-alone Murphy Express locations. MOUSA plans to build additional retail gasoline stations at Walmart Supercenters and other stand-alone locations in 2012 and beyond.

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Below is a table that lists the states where we operate Company-owned retail sites at December 31, 2011 and the number of retail sites in each state.

State	No. of stations	State	No. of stations	State	No. of stations
Alabama	65	Kansas	1	New Mexico	6
Arkansas	60	Kentucky	37	Ohio	42
Colorado	1	Louisiana	60	Oklahoma	50
Florida	99	Michigan	23	South Carolina	44
Georgia	77	Minnesota	7	Tennessee	75
Iowa	21	Missouri	46	Texas	236
Illinois	26	Mississippi	48	Virginia	3
Indiana	32	North Carolina	69	Total	1,128

Refined products are supplied from six terminals that are wholly owned and operated by MOUSA and at numerous terminals owned by others. Three of the wholly owned terminals are supplied by marine transportation and three are supplied by pipeline. MOUSA also receives products at terminals owned by others either in exchange for deliveries from the Company s terminals or by outright purchase.

The Company owns land underlying 899 of the stations on Walmart parking lots. No rent is payable to Walmart for the owned locations. For the remaining gasoline stations located on Walmart property that are not owned, Murphy has master agreements that allow the Company to rent land from Walmart. The master agreements contain general terms applicable to all rental sites in the United States. The terms of the agreements range from 10-15 years at each station, with Murphy holding two successive five-year extension options at each site. The agreements permit Walmart to terminate the agreements in their entirety, or only as to affected sites, at its option for the following reasons: Murphy vacates or abandons the property; Murphy improperly transfers the rights under this agreement to another party; an agreement or a premises is taken upon execution or by process of law; Murphy files a petition in bankruptcy or becomes insolvent; Murphy fails to pay its debts as they become due; Murphy fails to pay rent or other sums required to be paid within 90 days after written notice; or Murphy fails to perform in any material way as required by the agreements. Sales from the Company s U.S. retail marketing stations represented 47.4% of consolidated Company revenues in 2011, 53.1% in 2010 and 51.4% in 2009. As the Company continues to expand the number of retail operated gasoline stations, total revenue generated by this business is expected to grow. MOUSA s share of retail gasoline sales was approximately 2.6% of the total U.S. market during 2011.

In addition to the refined products sold at our retail gasoline stations, our stores carry a broad selection of snacks, beverages, tobacco products, and non-food merchandise. Our merchandise offer includes two private label products available at our retail stations, including an isotonic drink offered in several flavors and a private label energy drink. In 2011, we purchased more than 90% of our merchandise from a single vendor, McLane s Company, Inc., a wholly owned subsidiary of Berkshire Hathaway, Inc. The following table shows certain information with respect to our merchandise sales for the last three years:

	2011	2010	2009
Merchandise sales (in millions)	**$ 2,115.6**	1,969.2	1,706.3
Merchandise sales revenue per store month	**$ 158,144**	153,530	137,623
Merchandise margin as a percentage of merchandise sales	**12.8%**	13.1%	12.5%

In October 2009, MOUSA acquired an ethanol production facility located in Hankinson, North Dakota, to enter the renewable fuels business as a complement to our retail operations. The $92 million purchase price was primarily financed by $82 million of seller-provided nonrecourse debt. The Company chose in 2010 to pay off the nonrecourse debt early. The facility is designed to produce 110 million gallons of corn-based ethanol per year. Ethanol production in 2011 totaled 116.4 million gallons at Hankinson. The Company acquired a partially constructed ethanol production facility in Hereford, Texas, in late 2010. The Company paid $40 million for the

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facility at purchase and spent approximately $25.1 million to complete construction of the facility. The Hereford facility is designed with production capacity of 105 million gallons of corn-based ethanol per year, and commenced operation near the end of the first quarter of 2011. Total annualized ethanol production during the last six months of 2011 amounted to about 90 million gallons at Hereford. In addition to the ethanol production at each location, the Hankinson plant produces dried distillers grain with solubles (DDGS) and the Hereford plant produces wet distillers grains with solubles (WDGS), which are both sold to local farmers and other available outlets as an additional source of income. During 2011, the Company sold 358,000 tons of DDGS and 535,000 tons of WDGS.

Murphy owns an interest in a crude oil pipeline with a diameter of 24 inches that connects storage at the Louisiana Offshore Oil Port (LOOP) at Clovelly, Louisiana, to the Meraux refinery. Murphy owns a 40.1% interest in the first 22 miles of this pipeline from Clovelly to Alliance, Louisiana, and 100% of the remaining 24 miles from Alliance to Meraux. After the sale of the Meraux refinery in late 2011, the Company uses this pipeline to transport crude oil for two major companies for a throughput fee.

Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary, owns 100% interest in a refinery at Milford Haven, Pembrokeshire, Wales. The refinery is located on a 1,200 acre site owned by the Company; 750 acres are used by the refinery and the remainder is rented for agricultural use. The Milford Haven, Wales, refinery was shut down for a plant-wide turnaround in early 2010. During the downtime, the Company completed an expansion project that increased the plant s crude oil throughput capacity from 108,000 barrels per day to 135,000 barrels per day. The refinery has consistently performed at or above nameplate capacity during 2011. Murphy has announced its intention to sell the Milford Haven refinery as well as U.K. marketing assets.

Refinery capacities at Milford Haven, Wales at December 31, 2011 are shown in the following table.

Crude capacity barrels per stream day	135,000
Process capacity barrels per stream day	
Vacuum distillation	55,000
Catalytic cracking fresh feed	37,000
Naphtha hydrotreating	18,300
Catalytic reforming	18,300
Distillate hydrotreating	74,000
Isomerization	11,300
Production capacity barrels per stream day	
Alkylation	6,300
Crude oil and product storage capacity barrels	8,908,000

At the end of 2011, Murco distributed refined products in the United Kingdom from the wholly-owned Milford Haven refinery, three wholly owned terminals supplied by rail, six terminals owned by others where products are received in exchange for deliveries from the Company s terminals and eight terminals owned by others where products are purchased for delivery. At December 31, 2011, there were 233 Company stations, 222 of which were branded MURCO with the remainder under various third party brands. The Company owns the freehold under 149 of the sites and leases the remainder. The Company also supplied 226 MURCO branded dealer stations at year-end 2011.

In 2011, Murphy owned approximately 7.5% of the refining capacity in the United Kingdom. MURCO s fuel sales represented 2.1% of the total U.K. market share in 2011.

A statistical summary of key operating and financial indicators for each of the seven years ended December 31, 2011 are reported on page 6 of the 2011 Annual Report.

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Environmental

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

Further information on environmental matters and their impact on Murphy are contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 41 through 46.

Web site Access to SEC Reports

Our Internet Web site address is http://www.murphyoilcorp.com. Information contained on our Web site is not part of this report on Form 10-K.

Our 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 our Web site, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. Alternatively, you may access these reports at the SEC s Web site at *http://www.sec.gov.*

Item 1A. RISK FACTORS

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

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

If Murphy cannot replace its oil and natural gas reserves, it will 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 reserve additions and production by obtaining rights to explore for, develop and produce hydrocarbons in promising areas. In addition, it must find, develop and produce and/or purchase reserves at a competitive cost structure to be successful in the long-term. Murphy s ability to operate profitably in the exploration and production segments of its business, therefore, is dependent on its ability to find, develop and produce and/or purchase oil and natural gas reserves at costs that are less than the realized sales price for these products and at costs competitive with competing companies in the industry.

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

Proved oil and natural gas reserves included in this report on pages F-48 and F-49 have been prepared by qualified Company personnel or qualified independent engineers based on an unweighted average of oil and natural gas prices in effect at the beginning of each month in 2010 and 2011 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 crude oil and natural gas reservoirs. Estimates of economically recoverable crude oil and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods. Under existing SEC rules, reported proved reserves must be reasonably certain of recovery in future periods.

Actual future crude oil and natural gas production may vary substantially from the reported quantity of our 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, 2011, approximately 32% of the Company s proved oil reserves and 36% of proved natural gas reserves are undeveloped. The ability of the Company to reclassify these undeveloped proved reserves to the proved developed classification is generally dependent on the successful completion of one or more operations, which might include further development drilling, construction of facilities or pipelines, and well workovers.

The discounted future net revenues from our proved reserves as reported on page F-53 should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based on an unweighted average of the oil and natural gas prices in effect at the beginning of each month during the year. Actual future prices and costs may be materially higher or lower than those used in the reserves computations. In addition, the 10 percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the crude oil and natural gas business in general.

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

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 $95 per barrel in 2011, $80 per barrel in 2010 and $62 per barrel in 2009. Earnings for the exploration and production business were favorably impacted in 2011 by the higher oil prices. The Company s net income is also significantly affected by changes in the margins on refining and marketing operations. As demonstrated in 2011, the sales prices for oil and natural gas can be significantly different in U.S. markets compared to markets in foreign locations. The Company cannot predict how changes in the sales prices of oil and natural gas and changes in refining and marketing margins will affect its results of operations in future periods. Except in limited cases, the Company typically does not seek to hedge any significant portion of its exposure to the effects of changing prices of crude oil, natural gas and refined products. 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. However, certain oil and natural gas production, particularly in Sarawak Malaysia and the U.K., was sold at a premium to average U.S. natural gas prices in 2011 due to different pricing structures for gas in these regions.

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

The Company generally drills numerous wildcat wells each year which subjects its exploration and production operating results to significant exposure to dry holes expense, which have adverse effects on, and create volatility for, the Company s net income. In 2011, significant wildcat wells were primarily drilled offshore Brunei, Indonesia and Suriname. The Company s 2012 exploratory drilling program includes wells onshore in Western Canada and Kurdistan and offshore in the Gulf of Mexico, Brunei, Republic of the Congo, Australia and Malaysia.

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 may not fully cover capital funding requirements. Therefore, the Company maintains financing arrangements with lending institutions to meet certain funding needs. The Company must periodically renew these financing arrangements based on foreseeable financing needs or as they expire. The Company s primary bank financing facility was renewed in 2011 and now expires in June 2016. 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 September 2012. Outstanding notes of $350 million mature in April 2012. Although not considered likely, the Company may not be able in the future to sell notes at reasonable rates in the marketplace.

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

The ability of the Company to successfully manage development and operating costs is important because virtually all of the products it sells are energy commodities such as crude oil, natural gas and refined products, for which the Company has little or no influence on the sales prices or regional and worldwide consumer demand for these products. As an example, an economic slowdown in 2009 had a detrimental effect on the worldwide demand for these energy commodities, which effectively lead to reduced prices for oil, natural gas and refined products. Lower prices for crude oil and natural gas inevitably lead to lower earnings in the Company s exploration and production operations. Murphy is a net purchaser of crude oil and other refinery feedstocks in the U.K., and also purchases refined products, particularly gasoline, needed to supply its U.S. retail marketing stations. Therefore, its most significant costs are subject to volatility of prices for these commodities. The Company also often experiences pressure on its operating and capital expenditures in periods of strong crude oil, natural gas and refined product 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.

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 2011, approximately 19% of the Company s total production was at fields operated by others, while at December 31, 2011, approximately 38% 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, 2011, approximately 31% of proved reserves, as defined by the

U.S. Securities and Exchange Commission, were located in countries other than the U.S., Canada and the U.K. Certain of the reserves held outside these three 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 tax changes, royalty increases and regulations concerning: currency fluctuations, protection and remediation of the environment, concerns over the possibility of global warming being affected by human activity including the production and use of hydrocarbon energy, 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. Because these and other factors too numerous to list are subject to changes caused by governmental and political considerations and are often made in response to changing internal and worldwide economic conditions and to actions of other governments or specific events, it is not practical to attempt to predict the effects of such factors on Murphy s future operations and earnings.

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

The Company operates in urban and remote, and often inhospitable, areas around the world. The occurrence of an event, including but not limited to acts of nature such as hurricanes, floods, earthquakes and other forms of severe weather, and mechanical equipment failures, industrial accidents, fires, explosions, acts of war and intentional terrorist attacks 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. In May 2010, the U.S. President placed a temporary moratorium on new drilling in the Gulf of Mexico that forced the Company to defer planned exploration drilling in the Gulf of Mexico, and to renegotiate a drilling contract to move a deepwater drilling rig to Republic of the Congo. Further impacts of the accident and oil spill include added delays in deepwater Gulf of Mexico drilling activities, and additional future regulations covering offshore drilling operations, plus expected higher costs for future drilling operations and offshore insurance. The permitting delays and other restrictions associated with drilling and similar operations in the Gulf of Mexico are expected to have an adverse affect on the Company s, and likely many other companies , volume and 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, but the most severe storm activities usually occur in late summer, such as with Hurricanes Katrina and Rita in 2005. Other assets such as gasoline terminals and certain retail gasoline stations also lie near the Gulf of Mexico coastline and are vulnerable to storm damages. Although the Company maintains insurance for such risks as described below, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured.

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

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and property damage, including claims arising from sudden and accidental pollution events. The Company also maintains insurance coverage with an additional limit of $250 million per occurrence ($700 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. During 2005, damages from hurricanes caused a temporary shut-down of certain U.S. oil and gas production operations as well as the Meraux, Louisiana, refinery. The Company repaired the Meraux refinery and it restarted operations in mid-2006, but the Company did not fully recover repair costs incurred at Meraux under its insurance policies. See Note P in the consolidated financial statements for further discussion.

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.

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.

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

The Company s worldwide operational scope exposes it to risks associated with foreign currencies. Most of the Company s business is transacted in U.S. dollars, therefore, the Company and most of its subsidiaries are U.S. dollar functional entities for accounting purposes. However, the Canadian dollar is the functional currency for all Canadian operations and the British pound is the functional currency for U.K. refining and marketing operations. In certain countries, such as Malaysia, the United Kingdom and Canada, significant levels of transactions occur in currencies other than the functional currency. In Malaysia, such transactions include tax payments, while in the U.K., virtually all crude oil feedstock purchases and certain bulk product sales are priced in U.S. dollars, and in Canada, certain crude oil sales are priced in U.S. dollars. This exposure to currencies other than the functional currency can lead to significant impacts on consolidated financial results. In Malaysia, known future tax payments based in local currency are usually 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 if the ringgit weakens versus the dollar. Foreign exchange exposures between the U.S. dollar and the British pound are not hedged due to the frequency and volatility of U.S. dollar transactions in the U.K. downstream business. The Company would generally expect to incur currency losses when the U.S. dollar strengthens against the British pound. 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.

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, 2011.

Item 2. PROPERTIES

Descriptions of the Company s oil and natural gas and refining and marketing properties 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-46 to F-54 and in Note E Property, Plant and Equipment beginning on page F-17.

Executive Officers of the Registrant

The age at January 1, 2012, present corporate office and length of service in office 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.

David M. Wood Age 54; President and Chief Executive Officer and Director and Member of the Executive Committee since January 2009. Mr. Wood served as Executive Vice President responsible for the Company s worldwide exploration and production operations from January 2007 through December 2008 and President of Murphy Exploration & Production Company-International from March 2003 through December 2006.

Kevin G. Fitzgerald Age 56; 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.

Roger W. Jenkins Age 50; Executive Vice President Exploration and Production since August 2009. Mr. Jenkins has served as President of the Company s exploration and production subsidiary since January 2009. He was Senior Vice President, North America for this subsidiary from September 2007 to December 2008, and prior to that time, held various positions, including General Manager of the Company s exploration and production operations in Sabah, Malaysia.

Thomas McKinlay Age 48; Executive Vice President, World Wide Downstream Operations since January 2011. Mr. McKinlay was Vice President, U.S. Manufacturing from August 2009 to January 2011. Mr. McKinlay also became President of the Company s U.S. refining and marketing subsidiary effective January 2011 and was Vice President, Supply and Transportation of this subsidiary from April 2009 to January 2011. From August 2008 to March 2009, Mr. McKinlay was General Manager, Supply and Transportation of this U.S. subsidiary, and from January 2007 to August 2008 was Supply Director for the Company s U.K. refining and marketing subsidiary.

Bill H. Stobaugh Age 60; Executive Vice President, Corporate Planning & Business Development since February 2012. Mr. Stobaugh was Senior Vice President from February 2005 to January 2012.

Walter K. Compton Age 49; Senior Vice President and General Counsel since March 2011. Mr. Compton was Vice President, Law from February 2009 to February 2011 and was Manager, Law from November 1996 to January 2009.

John W. Eckart Age 53; 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.

Mindy K. West Age 42; Vice President and Treasurer since January 2007. Ms. West was Director of Investor Relations from July 2001 through December 2006.

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Kelli M. Hammock Age 40; Vice President, Administration since December 2009. Ms. Hammock was General Manager, Administration from June 2006 to November 2009.

Thomas J. Mireles Age 39; Vice President, Corporate Planning & Development since February 2012. Mr. Mireles was General Manager, Planning & Analysis from June 2010 to January 2012. He had previously served as Senior Manager, Business Development from February 2009 to May 2010 and was Manager, Business Development from January 2007 to January 2009.

John A. Moore Age 44; Secretary since March 2011. Mr. Moore was Senior Attorney from August 2005 to February 2011.

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.

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PART II

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

The Company s Common Stock is traded on the New York Stock Exchange using MUR as the trading symbol. There were 2,212 stockholders of record as of December 31, 2011. Information as to high and low market prices per share and dividends per share by quarter for 2011 and 2010 are reported on page F-55 of this Form 10-K report.

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, 2006 for the Company, the Standard & Poor s 500 Stock Index (S&P 500 Index) and the NYSE ARCA Oil Index. This performance information is furnished by the Company and is not considered as filed with this Form 10-K and it is not incorporated into any document that incorporates this Form 10-K by reference.

	2006	2007	2008	2009	2010	2011
Murphy Oil Corporation	100	169	89	111	156	119
S&P 500 Index	100	105	66	84	97	99
NYSE ARCA Oil Index	100	134	87	98	115	119

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Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	**2011**	2010	2009	2008	2007
Results of Operations for the Year					
Sales and other operating revenues	**$ 27,689,332**	20,225,764	16,800,972	24,134,820	15,573,086
Net cash provided by continuing operations	**1,999,875**	3,028,070	1,770,205	2,863,748	1,438,079
Income from continuing operations	**740,932**	779,559	713,854	1,764,631	560,570
Net income	**872,702**	798,081	837,621	1,739,986	766,529
Per Common share diluted					
Income from continuing operations	**$ 3.81**	4.03	3.71	9.18	2.93
Net income	**4.49**	4.13	4.35	9.06	4.01
Cash dividends per Common share	**1.10**	1.05	1.00	.875	.675
Percentage return on[1]					
Average stockholders equity	**9.9**	10.3	12.5	29.1	16.8
Average borrowed and invested capital	**9.2**	9.4	10.9	24.4	13.9
Average total assets	**5.7**	5.9	7.0	15.1	8.5
Capital Expenditures for the Year [2]					
Continuing operations					
Exploration and production	**$ 2,768,222**	2,034,828	1,807,561	1,928,346	1,740,327
Refining and marketing	**122,301**	290,090	263,413	348,476	481,959
Corporate and other	**5,218**	5,899	22,967	3,235	4,146
	2,895,741	2,330,817	2,093,941	2,280,057	2,226,432
Discontinued operations	**48,071**	117,323	113,328	84,629	130,915
	$ 2,943,812	2,448,140	2,207,269	2,364,686	2,357,347
Financial Condition at December 31					
Current ratio	**1.22**	1.21	1.55	1.51	1.37
Working capital	**$ 622,743**	619,783	1,194,087	958,818	777,530
Net property, plant and equipment	**10,475,149**	10,367,847	9,065,088	7,727,718	7,109,822
Total assets	**14,138,138**	14,233,243	12,756,359	11,149,098	10,535,849
Long-term debt	**249,553**	939,350	1,353,183	1,026,222	1,516,156
Stockholders equity	**8,778,397**	8,199,550	7,346,026	6,278,945	5,066,174
Per share	**45.31**	42.52	38.44	32.92	26.70
Long-term debt percent of capital employed[1]	**2.8**	10.3	15.6	14.0	23.0

1 Company management uses certain measures for assessing our 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, we measure our long-term debt leverage using long-term debt as a percentage of total capital employed (long-term debt plus stockholders equity). We consistently disclose these financial measures because we believe our shareholders and other interested parties find such measures helpful in understanding trends and results of the Company and as a comparison of Murphy Oil to other companies in our and other industries.

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

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

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

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

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

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

[2] Capital expenditures presented here 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.

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

Overview

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with petroleum marketing operations in the United States and refining and marketing operations in the United Kingdom. A more detailed description of the Company s significant assets can be found in Item 1 of this Form 10-K report.

Murphy generates revenue by selling oil and natural gas production to customers in the United States, Canada, Malaysia, the United Kingdom and other countries. Additionally, the Company generates revenue by selling refined petroleum and ethanol products at hundreds of locations in the United States and the United Kingdom. The Company s revenue is highly affected by the prices of oil, natural gas and refined petroleum products that it sells. Also, because crude oil is purchased by the Company for U.K. refinery feedstocks, natural gas is purchased for fuel at its U.K. refinery and at worldwide oil production facilities, and gasoline is purchased to supply its retail gasoline stations in the U.S. that are primarily located at Walmart Supercenters, the purchase prices for these commodities also have a significant effect on the Company s costs. 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, amortization of capital expenditures and expenses related to exploration and administration. Profits and generation of cash in the Company s refining and marketing operations are dependent upon achieving adequate margins, which are determined by the sales prices for refined petroleum products less the costs of purchased refinery feedstocks and gasoline and expenses associated with manufacturing, transporting and marketing these products. Murphy also incurs certain costs for general company administration and for capital borrowed from lending institutions and note holders.

Worldwide oil prices were significantly higher in 2011 than 2010, but North American natural gas prices were weaker in 2011 than in the prior year. The sales price for a barrel of West Texas Intermediate (WTI) crude oil averaged $95.11 in 2011, $79.61 in 2010 and $62.05 in 2009. The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $4.03 in 2011, $4.38 in 2010 and $3.94 in 2009. Crude oil prices rose in 2011 primarily due to a combination of recovering demand and unrest in the oil-rich Middle East and Northern Africa. While the 2011 prices of WTI crude oil rose almost 20% compared to the prior year, crude oil sold based on other worldwide benchmark prices, such as Brent and Tapis, rose even more than WTI. The rise in prices of WTI based crude oil, which is only used as a benchmark in North America, was held back in 2011 compared to other worldwide benchmark price increases due to a somewhat temporary crude oil dislocation discount and a bit of supply/demand disparity in the continental U.S. during the year. The average price of NYMEX natural gas was 8% lower in 2011 than 2010. The disparity between crude oil and natural gas prices in North America continued to widen during 2011 compared to an energy equivalent basis of six thousand cubic feet of gas to one barrel of oil due to gas production growth that exceeded demand. The increase in natural gas production was primarily associated with volumes produced at a number of expanding U.S. unconventional shale gas plays. Natural gas prices in North America have declined further in early 2012 due to milder than normal winter temperatures across much of the U.S. Crude oil and North American natural gas prices were both higher in 2010 than in 2009. Crude oil prices generally strengthened in 2010 as the worldwide economy began to show signs of recovery following the deep recession that began in 2008. WTI oil prices in 2010 averaged 28% higher than 2009, while NYMEX natural gas prices increased 11%. Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company, especially the price of crude oil as oil represented approximately 57% of the total hydrocarbons produced on an energy equivalent basis (one barrel of oil equals six thousand cubic feet of natural gas) by the Company in 2011. In 2012, the percentage of hydrocarbon production represented by oil is expected to remain relatively consistent with 2011. If the prices for crude oil and natural gas should weaken in 2012 or beyond, the Company would expect this to have an unfavorable impact on operating profits for its exploration and production business. Such lower oil and gas prices could, but may not, have a favorable impact on the Company s refining and marketing operating profits.

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Results of Operations

Net income in 2011 of $872.7 million ($4.49 per diluted share) was 9% better than net income in 2010 of $798.1 million ($4.13 per diluted share). The improvement in 2011 net income in comparison to 2010 was primarily attributable to higher oil prices in 2011 and stronger U.S. retail marketing and refining margins. These were mostly offset by an impairment charge of $368.6 million in 2011 to reduce the carrying value of the Azurite oil field offshore Republic of the Congo to fair value. The net cost of corporate activities not allocated to the operating segments was lower in 2011 than in 2010. Net income in 2011 included income from discontinued operations of $131.8 million ($0.68 per diluted share) compared to income from discontinued operations of $18.5 million ($0.10 per diluted share) in 2010. The results of discontinued operations in both years are associated with two U.S. refineries and certain associated marketing assets that were sold in 2011. Income from continuing operations was $740.9 million ($3.81 per diluted share) in 2011 compared to $779.6 million ($4.03 per diluted share) in 2010.

Murphy had net income in 2010 of $798.1 million ($4.13 per diluted share), down 5% compared to net income of $837.6 million ($4.35 per diluted share) in 2009. Net income in 2010 included income from discontinued operations of $18.5 million ($0.10 per diluted share), while 2009 had income from discontinued operations of $123.8 million ($0.64 per diluted share). The results of discontinued operations in 2010 were associated with operating income of the two U.S. refineries and associated marketing assets that were sold in 2011; income from discontinued operations in 2009 primarily arose from a $103.6 million after-tax gain on disposal of all Ecuador assets in March 2009, but also included operating income of the U.S. refineries and marketing assets sold in 2011. Income from continuing operations was $779.6 million ($4.03 per diluted share) in 2010 and $713.8 million ($3.71 per diluted share) in 2009. Income in 2010 rose for both exploration and production (E&P) and refining and marketing (R&M) operations compared to the prior year. Earnings for the Company s E&P operations increased in 2010 primarily due to higher sales prices and sales volumes of crude oil and natural gas. The Company s R&M earnings from continuing operations were higher in 2010 primarily due to stronger profits on U.S. retail gasoline fuel and merchandise sales. Earnings in 2010 were unfavorably affected compared to 2009 by higher net costs associated with Corporate activities that were not allocated to operating segments, with the higher costs primarily caused by an unfavorable variance for the effects of transactions denominated in foreign currencies.

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

2011 vs. 2010 Net income in 2011 totaled $872.7 million ($4.49 per diluted share) compared to $798.1 million ($4.13 per diluted share) in 2010. These earnings included income from discontinued operations of $131.8 million ($0.68 per diluted share) in 2011 compared to income of $18.5 million ($0.10 per diluted share) in 2009. Discontinued operations in both years were associated with the Company s two U.S. refineries which were sold in 2011. Income from continuing operations amounted to $740.9 million ($3.81 per diluted share) in 2011, down from $779.6 million ($4.03 per diluted share) in 2010. The lower earnings from continuing operations in 2011 was primarily attributable to a $368.6 million impairment charge to reduce the carrying value of the Azurite oil field, offshore Republic of the Congo, to fair value. Higher sales prices for worldwide crude oil and Sarawak natural gas production and higher U.S. retail marketing profits partially offset the impact of the Congo impairment.

E&P income in 2011 was $181.2 million lower than 2010, primarily attributable to the $368.6 million impairment charge at the Azurite oil field in Republic of the Congo. Other unfavorable impacts in 2011 included higher dry hole costs compared to 2010, lower crude oil sales volumes, lower North American natural gas sales prices and higher extraction costs for oil and gas produced in 2011. E&P results in 2011 benefited from a 41% higher average sales prices for crude oil produced and a 34% higher sales prices for natural gas produced offshore Sarawak, Malaysia. Income from R&M continuing operations was $59.7 million higher in 2011 compared to 2010, essentially attributable to stronger U.S. retail gasoline marketing margins of more than $0.04 per gallon and larger profits on sales of merchandise in the U.S. retail marketing business. The net costs of corporate activities were $82.8 million less in 2011 than 2010 primarily due to gains from transactions

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denominated in foreign currencies in 2011 compared to losses on such transactions in 2010. During 2011 the U.S. dollar generally strengthened in comparison to the Malaysian ringgit, which provided a favorable foreign currency impact to the Company s earnings due to fewer U.S. dollars being required to pay 2011 and future income taxes owed in the local currency.

Sales and operating revenues were $7.5 billion more in 2011 than 2010 primarily due to higher prices realized on crude oil production and gasoline and other refined products sold by the Company. Gain on sale of assets classified in continuing operations was $21.8 million more in 2011 than 2010 principally due to a profit on sale of gas storage assets in Spain in the current year. Interest and other income (loss) in 2011 was favorable $90.5 million compared to 2010 principally due to improved income effects from transactions denominated in foreign currencies. Additionally, the Company collected higher interest income on invested cash balances in 2011 primarily due to larger average invested balances during the year. Crude oil and product purchases expense was $6.5 billion more in 2011 than 2010 due to higher costs of crude oil feedstocks at the Milford Haven, Wales refinery, higher costs for gasoline purchased for resale in the U.S. retail marketing operations and an increase in volume of merchandise purchased for resale at U.S. retail gasoline stations. Operating expenses in 2011 were $314.8 million more than 2010 mostly due to higher costs associated with the Company s production of oil and natural gas in 2011, plus higher operating expenses at U.S. retail marketing stations, and higher power and other costs at the Milford Haven, Wales refinery. Exploration expense in 2011 was $197.6 million above 2010 primarily due to higher dry hole costs associated with unsuccessful exploratory drilling activities in Brunei, Indonesia, Canada and Suriname. Selling and general expenses rose $41.8 million in 2011 compared to 2010 primarily due to a combination of higher costs for employee compensation and professional services. Depreciation, depletion and amortization expense was down $21.1 million in 2011 mostly due to fewer barrels of oil equivalent produced in 2011 compared to 2010. Impairment of long-lived assets of $368.6 million in 2011 was attributable to a charge to reduce the net book value of the Azurite oil field to fair value. The charge was necessitated by a reduction of proved oil reserves at this field at year-end 2011. Accretion of asset retirement obligations increased $5.8 million in 2011, primarily due to future abandonment costs to be incurred on oil and gas development wells drilled in the Eagle Ford Shale and Montney areas in 2011, and higher estimated abandonment costs for existing wells in the Gulf of Mexico and offshore Malaysia and for synthetic oil operations at Syncrude in Western Canada. The income effect of the redetermination of the Company s working interest at the Terra Nova field, offshore Eastern Canada, was favorable $23.9 million in 2011 compared to 2010. The final settlement related to the redetermination was made in early 2011 at a net cost to the Company that was $5.4 million less than previously estimated. The benefit from this reduced settlement payment was recognized in 2011. The net cost of $18.6 million in 2010 related to the portion of Terra Nova s operating results in 2010 that were estimated to be owed to other partners upon final settlement. Due to the redetermination process, the Company s working interest at Terra Nova was reduced from 12.0% to 10.475%. Interest expense in 2011 was $2.7 million more than 2010 primarily due to interest associated with tax reassessments in Canada in the most recent year. Interest capitalized to oil and gas development projects in 2011 was $3.3 million below 2010 due to cessation of interest capitalized upon commencement of production at the Tupper West area in Western Canada in the first quarter 2011. Income tax expense was $200.9 million more in 2011 than 2010 due to higher pretax income in 2011 plus higher exploration and impairment expenses in the year for which no tax benefit was recognizable by the Company. The effective tax rate on a consolidated basis increased from 43.9% in 2010 to 52.2% in 2011 due to a larger percentage of earnings in higher tax jurisdictions in 2011 and due to higher exploration, impairment and other expenses in foreign jurisdictions where no income tax benefit can presently be recognized due to no assurance that these expenses would be realized in 2011 or future years to reduce taxes owed. The tax rates in both 2011 and 2010 were higher than the U.S. federal statutory rate of 35.0% due to a combination of U.S. state income taxes, certain foreign tax rates 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 expenses in 2011 or future years. Income from discontinued operations was $113.2 million higher in 2011 than 2010 due to stronger U.S. refining margins in 2011 prior to the sale of the refineries near the end of the third quarter of 2011. Additionally, 2011 discontinued operations included a pretax gain on sale of the two U.S. refineries of $18.7 million.

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2010 vs. 2009 Net income in 2010 was $798.1 million ($4.13 per diluted share) compared to $837.6 million ($4.35 per diluted share) in 2009. The 2010 and 2009 results included income from discontinued operations of $18.5 million ($0.10 per diluted share) and $123.8 million ($0.64 per diluted share), respectively. The discontinued operations income in 2010 included the operating results of the Meraux, Louisiana, and Superior, Wisconsin, refineries and associated marketing assets that were sold in 2011. The 2009 discontinued operations income included the operating results of these two refineries plus properties in Ecuador that were sold in March 2009 at an after-tax gain of $103.6 million. Income from continuing operations in 2010 and 2009 were $779.6 million ($4.03 per diluted share) and $713.8 million ($3.71 per diluted share), respectively. The higher 2010 income from continuing operations compared to 2009 was caused by higher earnings in both the E&P and R&M businesses, but these were partially offset by higher net costs for unallocated corporate activities.

E&P income from continuing operations improved $115.1 million in 2010, primarily due to a $10.70 per barrel higher realized sales price for crude oil in 2010. The 2009 results were impacted by two unusual items. First, an after-tax gain of $158.3 million in 2009 was derived from a recovery of certain deepwater Gulf of Mexico federal royalties paid in prior years. Second, an after-tax charge of $58.4 million was recorded in 2009 associated with a required one-time working interest redetermination at the Terra Nova field, offshore Eastern Canada. The 2010 E&P results were also favorably affected, but in less significant measures, by higher sales volumes for crude oil and natural gas and higher sales prices for natural gas. E&P was unfavorably affected in 2010 compared to the prior year by higher expenses for exploration, production, depreciation and administration. Income from R&M continuing operations was $85.6 million more in 2010, with the improvement mostly attributable to slightly more than a $0.03 per gallon improvement in margins on sale of gasoline at U.S. retail marketing stations. This was partially offset by higher net losses in 2010 for U.K. R&M operations. The net costs of corporate activities were higher by $134.9 million in 2010, mostly attributable to unfavorable effects of transactions denominated in foreign currencies. To a lesser degree, the 2010 corporate net costs were unfavorably affected by lower interest income and higher expenses for interest and administration. The unfavorable variance in foreign currency transactions in 2010 was primarily attributable to a strengthening of the Malaysian ringgit versus the U.S. dollar and weakening of the British pound sterling against the U.S. dollar during the year.

Sales and other operating revenues grew $3.4 billion in 2010 compared to 2009 mostly due to higher sales prices for gasoline and other motor fuels in the later year. Additionally, higher sales prices and sales volumes for crude oil and natural gas in the E&P segment contributed to the increase in 2010 revenue. Gain on sale of assets was $2.8 million less in 2010 than 2009 because the earlier year included a $3.9 million gain on sale of a small Canadian natural gas field. Interest and other operating income (loss) was unfavorable by $147.4 million in 2010 compared to 2009 mostly due to a $114.3 million unfavorable variance from the effects of transactions denominated in foreign currencies, plus nonrecurring interest income in 2009 of $42.0 million associated with a recovery of Federal royalties paid in prior years for production at certain deepwater Gulf of Mexico fields. The expense associated with crude oil and product purchases increased by $2.5 billion in 2010 compared to 2009 due to higher average costs for wholesale gasoline and other motor fuels which were purchased for resale at the Company s retail fueling stations in the U.S. and U.K. and higher costs for crude oil feedstocks at the Company s U.K. refinery. Operating expenses were $327.9 million higher in 2010 than 2009 due to a combination of higher oil and natural gas production costs and higher costs for U.S. retail gasoline station operations. Exploration expenses rose $27.1 million in 2010 compared to 2009 due to higher geophysical costs in the Gulf of Mexico and Republic of the Congo, higher amortization expense for undeveloped leases in the Eagle Ford Shale, and higher administrative office and study costs in foreign locations. Exploration costs in 2010 included lower dry hole costs in Malaysia, Australia and the U.S., which more than offset higher dry hole costs in Republic of the Congo, Suriname and the U.K. Selling and general expenses were $46.8 million more in 2010 than in 2009 primarily due to higher employee compensation costs. Depreciation, depletion and amortization expense rose $243.5 million in 2010 versus 2009 due to higher natural gas and crude oil sales volumes in 2010, higher E&P per-unit depreciation rates, and higher R&M depreciation that included a new ethanol production facility, more U.S. retail gasoline stations in operation and a crude unit expansion at the Milford Haven, Wales, refinery that was completed in 2010. Impairment of properties was nil in 2010 and $5.2 million in 2009, with the earlier year costs related to write-off of an underperforming natural gas field in the Gulf of Mexico. Accretion of asset retirement obligations was $5.7 million more in 2010 than 2009 primarily due to higher discounted abandonment liabilities in 2010 for wells drilled in Malaysia and for synthetic oil operations at Syncrude. Expense for redetermination of working interest at the Terra Nova field was $64.9 million less in 2010 than 2009 because the earlier year included cumulative costs for the period of December 2004 through 2009, while 2010 costs related only to that year s operations at Terra Nova. Interest expense was $0.2 million higher in 2010 primarily due to nine months of interest in 2010 on nonrecourse debt associated with the Hankinson, North Dakota, ethanol production facility, compared to three months of interest on this debt in 2009 following the October 1, 2009 acquisition date. The nonrecourse debt was paid off by the Company in September 2010. The higher nonrecourse debt interest was mostly offset by lower interest expense on outstanding general bank financing balances in 2010. Capitalized interest was $10.2 million less in 2010 than in the prior year due to interest amounts allocated to the Sarawak natural gas development in 2009 prior to start-up of operations later that year, partially offset by higher interest allocated to the Tupper West gas development in 2010. Income tax expense in 2010 was $87.6 million more than 2009 due to higher pretax earnings and a slightly higher overall effective tax rate in the later year. The consolidated effective tax rate was 43.9% in 2010 compared to 42.2% in 2009, with the rate increase in the later year caused by a larger percentage of earnings in higher tax jurisdictions in 2010 and due to higher current year exploration and other expenses in foreign jurisdictions where no income tax benefit can presently be recognized due to no assurance that these expenses will be realized in 2010 or future years to reduce taxes owed. The tax rates in both 2010 and 2009 were higher than the U.S. federal statutory tax rate of 35.0% due to a combination of U.S. state income taxes, certain foreign tax rates 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 2010 or future years. Income from discontinued operations was $18.5 million ($0.10 per diluted share) in 2010 and $123.8 million ($0.64 per diluted share) in 2009. Income from discontinued operations in both years included operating results for the two U.S. petroleum refineries sold in late 2011. Income from discontinued operations in 2009 included an after-tax gain of $103.6 million on Ecuador assets which were sold in March 2009.

Segment Results In the following table, the Company s results of operations for the three years ended December 31, 2011, are presented by segment. More detailed reviews of operating results for the Company s exploration and production and refining and marketing activities follow the table.

(Millions of dollars)	**2011**	2010	2009
Exploration and production continuing operations			
United States	**$ 152.7**	72.7	178.0
Canada	**328.0**	213.8	64.8
Malaysia	**812.7**	659.4	561.9
United Kingdom	**11.5**	30.5	12.6
Republic of the Congo	**(385.3)**	(77.2)	(20.6)
Other	**(293.9)**	(92.3)	(104.9)
	625.7	806.9	691.8
Refining and marketing continuing operations			
United States	**223.6**	165.3	65.5
United Kingdom	**(33.3)**	(34.7)	(20.5)
	190.3	130.6	45.0
Corporate and other	**(75.1)**	(157.9)	(23.0)
Income from continuing operations	**740.9**	779.6	713.8
Income from discontinued operations	**131.8**	18.5	123.8
Net income	**$ 872.7**	798.1	837.6

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Exploration and Production Earnings from exploration and production (E&P) continuing operations were $625.7 million in 2011, $806.9 million in 2010 and $691.8 million in 2009.

E&P income in 2011 was $181.2 million less than in 2010 primarily due to a $368.6 million impairment charge in 2011 to reduce the carrying value of the Azurite oil field to fair value. The 2011 period also had higher exploration expense, lower crude oil sales volumes and lower North American natural gas sales prices. But the latest year benefited from higher oil and Sarawak natural gas sales prices and higher natural gas sales volumes. The Company s realized crude oil sales prices averaged $27.43 per barrel more in 2011 than 2010. North American natural gas sales prices in 2011 were $0.26 per MCF below 2010 levels, but natural gas sales prices from fields offshore Sarawak were higher in 2011 by $1.79 per MCF. Crude oil, condensate and gas liquids sales volumes were 22% lower in 2011 compared to 2010, compared to a decrease in oil production volumes of 19% in 2011. Oil sales volumes declined more than oil production volumes during 2011 primarily due to the timing of scheduling oil sales transactions at the Kikeh field offshore Malaysia. Sales volumes at Kikeh were below production levels in 2011 due to an increase in the volume of unsold barrels at the field at the latest year-end, while in 2010, Kikeh sales volumes exceeded production, which effectively reduced the Company s unsold inventory balance from year-end 2009. U.S. crude oil sales volumes were lower in 2011 than 2010 principally due to less production at the Thunder Hawk field in the Gulf of Mexico. Lower crude oil sales volumes in Canada in 2011 were mostly attributable to production issues and a lower Company working interest percentage in 2011 at the Terra Nova field, but this was partially offset by higher sales volumes at the Seal heavy oil field in Alberta. Crude oil sales volume in the U.K. in 2011 were below 2010 levels primarily due to lower oil volumes produced at the Schiehallion and Mungo/Monan fields during the later year. Crude oil sales volumes at Kikeh in 2011 fell compared to 2010 due to lower annual production in 2011 caused by well downtime for mechanical issues. Sales of crude oil and condensate increased at fields offshore Sarawak in 2011 due to higher volumes produced during the year. Crude oil sales volumes in Republic of the Congo fell in 2011 due to production decline at the Azurite field. Natural gas sales volumes increased 28% in 2011 and the improvement was primarily attributable to higher gas volumes produced during 2011 at the Tupper West area in Western Canada following start-up in the first quarter of the year. Natural gas sales volumes also improved in 2011 at the Tupper area in Canada and at fields offshore Sarawak; both of these areas had active development programs during 2011. Natural gas sales volumes were lower during 2011 at the Kikeh field principally due to less volumes produced because of mechanical issues with wells.

Income from E&P continuing operations in 2010 was $115.1 million more than in 2009. The increase was primarily attributable to higher sales prices for crude oil and other liquid hydrocarbons produced in 2010. The Company s average realized sales price for crude oil, condensate and gas liquids in 2010 increased $10.70 per barrel over 2009. The Company s average natural gas sales prices in North America and Sarawak Malaysia were also higher in 2010 than 2009. E&P income in 2009 included a $158.3 million after-tax one-time benefit from recovery of previously paid federal royalties associated with certain fields in the deep waters of the Gulf of Mexico. Although both 2010 and 2009 had charges associated with a redetermination of working interest at the Terra Nova field offshore Eastern Canada, 2009 charges were higher by $64.9 million due to 2009 including estimated costs to settle the period from December 2004 to 2009, while 2010 included only costs for that year s operating activities. Earnings in 2010 benefited from higher crude oil and natural sales volumes compared to 2009. Crude oil and liquids sales volumes increased 2% in 2010 while natural gas sales volumes rose 91%. The increase in hydrocarbon sales volumes in 2010 led to higher expenses for production and depreciation of $225.0 million and $229.2 million, respectively. The 2010 year also had higher exploration expenses of $27.1 million compared to 2009, essentially due to higher expenses related to geophysical activities, undeveloped lease amortization and administration, which were somewhat offset by lower expenses for dry holes. Crude oil sales volumes increased in 2010 in the U.S. due to a full year of production at the Thunder Hawk field in the Gulf of Mexico; this field started producing in July 2009. Heavy oil sales volumes in Canada in 2010 were less than 2009 due to lower gross production and a higher royalty rate in the Seal area of Western Canada. Oil sales volumes in 2010 offshore Canada were below 2009 levels mostly due to lower gross production at the Terra Nova field and a higher royalty rate at the Hibernia field. Synthetic oil sales at Syncrude increased in 2010 due to higher gross production compared to 2009. Sales volumes for crude oil produced in Malaysia were lower

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in 2010 due to less production at the Kikeh field offshore Sabah. Crude oil sold in the U.K. rose in 2010 due to making up for undersold inventory barrels produced in 2009 at the Schiehallion field. Crude oil sales increased in 2010 in Republic of the Congo due to a full year of production at the Azurite field following production start-up in August 2009. Natural gas sales volumes in 2010 increased significantly compared to the prior year due to a full year of production and higher daily sales volumes at gas fields which started up in 2009 offshore Sarawak Malaysia, as well as higher sales volumes at the Tupper area in Western Canada.

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-51 and F-52 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 5 of the 2011 Annual Report.

A summary of oil and gas revenues, including intersegment sales that are eliminated in the consolidated financial statements, is presented in the following table.

(Millions of dollars)	**2011**	2010	2009
United States			
Oil and gas liquids	**$ 648.8**	557.6	374.8
Natural gas	**71.1**	87.0	80.6
Canada			
Conventional oil and gas liquids	**505.6**	388.6	365.6
Synthetic oil	**506.6**	378.6	288.5
Natural gas	**280.2**	132.1	68.6
Malaysia			
Oil and gas liquids	**1,583.0**	1,531.1	1,478.4
Natural gas	**461.3**	307.1	45.4
United Kingdom			
Oil and gas liquids	**92.4**	118.8	54.7
Natural gas	**14.3**	14.1	6.4
Republic of the Congo oil	**148.8**	156.7	24.5
Total oil and gas revenues	**$ 4,312.1**	3,671.7	2,787.5

The Company s total crude oil, condensate and natural gas liquids production from continuing operations, which excludes discontinued operations in Ecuador sold in March 2009, averaged 103,160 barrels per day in 2011, 126,927 barrels per day in 2010 and 130,522 barrels per day in 2009.

United States oil production decreased from 20,114 barrels per day in 2010 to 17,148 barrels per day in 2011 with the lower volumes mostly caused by field decline at Thunder Hawk that was primarily caused by a delay in development drilling operations in 2010 and 2011 following the Macondo incident in April 2010. The production decline at Thunder Hawk was partially offset by higher oil volumes produced in 2011 at the Eagle Ford Shale area in South Texas. Production of heavy oil in the Western Canada Sedimentary Basin was 7,264 barrels per day in 2011, up from 5,988 barrels per day in 2010, primarily due to ongoing drilling operations at the Seal area in Alberta. Oil production offshore Canada fell from 11,497 barrels per day in 2010 to 9,204 barrels per day in 2011 primarily due to field decline at Terra Nova and a reduction of the Company s working interest at this field from 12.0% in 2010 to 10.475% in 2011. Synthetic oil operations at Syncrude had net production of 13,498 barrels per day in 2011, up from 13,273 barrels per day in 2010, with the increase caused by a lower royalty rate in 2011 due to higher costs incurred for the operations. Oil production in Malaysia decreased from 66,897 barrels per day in 2010 to 48,551 barrels per day in 2011, primarily due to lower production at the Kikeh field. Sands and other fines produced with the oil at Kikeh led to certain wells being down for a portion of 2011. Oil production in Malaysia was favorably affected in 2011 by higher condensate and other gas liquids produced at gas fields offshore Sarawak. Oil production in the U.K. was 2,423 barrels per day in 2011, down from 3,295 barrels per day in 2010, with the decline primarily due to more downtime at the Schiehallion and Mungo/Monan fields during the later year. The Azurite field offshore Republic of the Congo averaged 4,989 barrels per day in 2011, down from 5,820 barrels per day in 2010 due to faster than expected well decline.

United States crude oil production averaged 20,114 barrels per day in 2010, up from 17,053 barrels per day in 2009. The U.S. increase was primarily attributable to a full year of oil production at the Thunder Hawk field that started up in July 2009 in the Gulf of Mexico. Heavy oil production in Western Canada declined from 6,813 barrels per day in 2009 to 5,988 barrels per day in 2010 due to a combination of lower gross production in the Seal area plus a higher royalty rate there due to higher sales prices in 2010. Crude oil production offshore Canada fell from 12,357 barrels per day in 2009 to 11,497 barrels per day in 2010 essentially due to lower production levels at Terra Nova caused by field decline and a higher royalty rate at Hibernia. Synthetic oil production of 13,273 barrels per day in 2010 exceeded 2009 volumes of 12,855 per day due to less downtime for maintenance in the later year. Crude oil and liquids production in Malaysia averaged 66,897 barrels per day in 2010, down from 76,322 barrels per day in 2009, with the decrease mainly due to downtime in the later year at Kikeh for well maintenance and installation of drilling equipment on the production facility. Crude oil production in the U.K. in 2010 was about flat with 2009 as higher production volumes at Schiehallion almost offset lower volumes due to well decline at Mungo/Monan. Oil production in Republic of the Congo rose to 5,820 barrels per day in 2010 after averaging 1,743 barrels per day for all of 2009; the Azurite field came on production in August 2009. The Company sold its interest in Block 16 and other areas in Ecuador in March 2009 and has accounted for Ecuador as discontinued operations. Oil production in Ecuador, excluded from the totals for continuing operations, averaged 1,317 barrels per day in 2009.

Worldwide sales of natural gas were 457.4 million cubic feet (MMCF) per day in 2011, 356.8 MMCF per day in 2010 and 187.3 MMCF per day in 2009.

Natural gas production in the U.S. averaged 47.2 MMCF per day in 2011, compared to 53.0 MMCF per day in 2010. The lower volume in 2011 was primarily attributable to the Thunder Hawk field where production declined during the year due to delay in development drilling operations following the Macondo incident in April 2010. Natural gas production in Canada rose from 85.6 MMCF per day in 2010 to an annual Company record of 188.8 MMCF per day in 2011 primarily due to start up of production at the Tupper West area in Western Canada in the first quarter 2011. Gas sales volumes also increased in 2011 at the nearby Tupper area due to development drilling activities during the year. Natural gas production in Malaysia rose to 217.4 MMCF per day in 2011 compared to 212.7 MMCF per day in 2010. Natural gas sales volumes during 2011 at Sarawak and Kikeh averaged 176.9 MMCF per day and 40.5 MMCF per day, respectively. Gas sales rose 22.4 MMCF per day at Sarawak due to higher demand from the local purchaser, while Kikeh gas volumes fell 17.7 MMCF per day in 2011 due to lower demand and wells down for mechanical repairs for a portion of the year. Natural gas production in the U.K. fell from 5.5 MMCF per day in 2010 to 3.9 MMCF per day in 2011 primarily due to more downtime for repairs at the Amethyst field during the just completed year.

Natural gas sales volumes in the U.S. were 53.0 MMCF per day in 2010, down from 2009 production of 54.2 MMCF per day as higher production at Thunder Hawk in the Gulf of Mexico and the Eagle Ford Shale area did not fully offset declines at fields onshore South Louisiana and at other fields in the Gulf of Mexico. Natural gas volumes in Western Canada increased from 54.9 MMCF per day in 2009 to 85.6 MMCF per day in 2010 essentially due to continued ramp-up of Tupper area production during the later year. Natural gas sales volumes in Malaysia increased in 2010 for both the Sarawak and Sabah offshore areas. Sarawak production rose to 154.5 MMCF per day in 2010 following volumes of 28.1 MMCF per day in 2009. Sarawak gas production began in September 2009 and as such was on production for all of 2010 versus four months in 2009. The Company also continued ramp-up of new wells at Sarawak gas fields during 2010. Gas sales at the Kikeh field averaged 58.2 MMCF per day in 2010, up from 46.6 MMCF per day the prior year. Natural gas sales volumes in the U.K. increased from 3.5 MMCF per day in 2009 to 5.5 MMCF per day in 2010 as gas volumes rose at both the Mungo/Monan and Amethyst fields during the later year.

The Company s average worldwide realized sales price for crude oil, condensate and gas liquids from continuing operations was $94.54 per barrel in 2011 compared to $67.11 per barrel in 2010 and $56.41 per barrel in 2009.

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The Company s average realized oil sales price of $94.54 in 2011 was an increase of 41% compared to 2010. The average price of West Texas Intermediate (WTI) crude oil rose 19% during 2011. The Company s average oil price increased more than WTI because other worldwide benchmark prices rose more than WTI during 2011. Dated Brent prices, for example, rose 40% during 2011. Additionally, the Company s realized sales price in Malaysia in 2011 and a portion of 2010 benefited from a switch to the Brent benchmark price during the prior year. Crude oil prices strengthened in 2011 due to an improvement in energy demand in association with a slowly recovering worldwide economy and unrest in Northern Africa and the Middle East during 2011 that caused concern in the oil markets about the potential for supply disruptions. Compared to 2010, the Company s average 2011 crude oil sales prices in the U.S. rose 36% to $103.92 per barrel; heavy oil prices in Canada sold for 14% more and averaged $57.00 per barrel; offshore Canada prices increased 43% to $110.02 per barrel; synthetic crude oil sold for 32% more at $102.94 per barrel; crude oil in Malaysia was up 48% and averaged $90.14 per barrel; U.K. crude oil production sold for 41% more at $110.13 per barrel; and crude oil in Republic of the Congo sold at $103.02 per barrel in 2011, an increase of 38% from 2010.

The average realized crude oil sales price increased 19% in 2010 compared to 2009. The higher price for 2010 was slightly below the 28% increase in WTI sales price between the years. Other benchmark oil prices used for sale of Company crude oil did not increase at the same rate as WTI. The increase in the sales price for APPI Tapis based crude oil during 2010 did not keep pace with the increase in the WTI price due to differences in market conditions in Asia versus the U.S. During most of 2010, the Company sold its Kikeh crude oil based on the APPI Tapis benchmark price. In late 2010, the Company began to sell its Kikeh crude oil based on a Brent crude oil benchmark. Compared to 2009, the Company s average 2010 crude oil sales prices rose 27% in the U.S. to average $76.31 per barrel; heavy oil sales prices in Canada rose 23% to an average of $49.89 per barrel; offshore Canada oil sold at $76.87 per barrel, an increase of 32%; Canadian synthetic crude oil sold for 27% more and averaged $77.90 per barrel; crude oil produced in Malaysia increased 10% to an average price of $60.97 per barrel; U.K. crude oil prices increased 27% to $77.95 per barrel; and crude oil sold in Republic of the Congo increased only 8% to $74.87 per barrel as the only sale in 2009 was near the end of the year when prices were above the 2009 average.

The Company s natural gas sales prices in North America in 2011 did not generally increase in concert with crude oil prices. A growing gas supply from unconventional sources such as shale operations kept gas prices in check during the latest year. The Company s average realized North American natural gas sales price was $4.08 per thousand cubic feet (MCF) in 2011, a decline of 6% from the $4.34 per MCF realized in 2010. Natural gas produced in 2011 offshore Sarawak was sold at an average price of $7.10 per MCF, an increase of 34% from the $5.31 per MCF realized during 2010. In the U.K. the average sales price rose from $7.01 per MCF in 2010 to $9.99 per MCF in 2011, up 43% in the current year.

Virtually all natural gas prices showed improvements in 2010 compared to 2009. The prices for natural gas generally rose in 2010 in sympathy with the increase in average crude oil prices during the same period. The Company s average sales prices for natural gas in North America increased 22% to $4.34 per MCF in 2010. Natural gas produced offshore Sarawak sold for 31% more in 2010 than in 2009 and averaged $5.31 per MCF in the later year. Natural gas produced in the U.K. sold at an average of $7.01 per MCF in 2010, a 39% increase from 2009.

Based on 2011 sales volumes and deducting taxes at marginal rates, each $1.00 per barrel and $0.10 per MCF fluctuation in prices would have affected 2011 earnings from exploration and production continuing operations by $23.5 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 refining and marketing segments could be affected differently.

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Production expenses from continuing operations were $1,038.6 million in 2011, $879.5 million in 2010 and $654.5 million in 2009. These amounts are shown by major operating area on pages F-51 and F-52 of this Form 10-K report. Costs per equivalent barrel during the last three years are shown in the following table.

(Dollars per equivalent barrel)	**2011**	2010	2009
United States	**$ 18.05**	12.46	10.62
Canada			
Excluding synthetic oil	**8.65**	8.45	9.44
Synthetic oil	**47.91**	42.61	36.64
Malaysia	**13.66**	9.31	8.00
United Kingdom	**26.24**	14.46	17.97
Republic of the Congo	**26.04**	31.30	43.51
Worldwide excluding synthetic oil	**13.39**	10.51	9.21

Production expense per equivalent barrel in the U.S. increased in 2011 compared to 2010 due to lower volumes produced at the Thunder Hawk field and higher facility rental costs in the early days of the Eagle Ford Shale operation as production ramped up. The per-unit cost for Canadian conventional oil and gas operations, excluding synthetic oil, was slightly higher in 2011 compared to 2010 as the benefit of significantly higher natural gas production at Tupper West and Tupper was more than offset by lower production volumes without a comparable reduction in costs at Hibernia and Terra Nova. Higher cost per barrel in 2011 compared to 2010 at Canadian synthetic oil operations was mostly caused by higher overall maintenance and fuel costs. Production cost per unit in Malaysia was higher in 2011 compared to 2010 primarily at Kikeh caused by higher costs for the work program to address equipment damaged by sand produced with the oil and the associated downtime which led to lower oil production. Higher per-barrel production expense in the U.K. in 2011 compared to 2010 was primarily attributable to lower production levels at all fields and extended maintenance work. Production expense in Republic of the Congo was lower on a per-unit basis in 2011 compared to 2010 due to lower gross costs incurred at the Azurite field in the later year.

Production expense per equivalent barrel in the U.S. increased in 2010 compared to 2009 due to a larger proportion of production in the later year coming from the higher-cost Thunder Hawk field in the Gulf of Mexico. Cost per barrel for Canada conventional oil and gas operations, excluding synthetic oil, was lower in 2010 than 2009 due to a larger portion of total hydrocarbons produced coming from the Tupper gas area, but this was partially offset by higher unit costs for offshore operations at Hibernia and Terra Nova. The increase in production costs per barrel for synthetic oil operations in 2010 compared to 2009 was caused by higher maintenance and natural gas costs in the current year. Production expense in Malaysia rose in 2010 compared to 2009 as higher well maintenance and workover costs at Kikeh were only partially offset by a higher proportion of lower-cost natural gas produced at fields offshore Sarawak. Production expense in 2010 in the U.K. on a per-unit basis was lower than 2009 due to less repair costs at Schiehallion and higher natural gas production at Amethyst. Per-unit production expense in 2010 in Republic of the Congo was less than in 2009 due to higher production levels associated with ramp-up of the Azurite field, which came onstream in August 2009.

Exploration expenses from 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-51 and F-52 on this Form 10-K report. Expenses other than leasehold amortization are included in the capital expenditures total for exploration and production activities.

(Millions of dollars)	**2011**	2010	2009
Dry holes	**$ 251.0**	90.1	125.3
Geological and geophysical	**79.7**	65.1	40.5
Other	**41.0**	29.1	16.2
	371.7	184.3	182.0
Undeveloped lease amortization	**118.2**	108.0	83.2
Total exploration expenses	**$ 489.9**	292.3	265.2

Dry hole expense was $160.9 million higher in 2011 than 2010 due to more unsuccessful exploratory drilling results in the current year, with the most significant areas including Brunei, Indonesia, Southern Alberta and Suriname. Lower dry hole costs in 2011 in Malaysia, Republic of the Congo and the U.K. somewhat offset the higher costs noted above. Geological and geophysical (G&G) expenses were $14.6 million higher in 2011 compared to 2010. The increase in G&G expenses in 2011 was attributable to higher spending on seismic in Brunei, the Kurdistan region of Iraq, Block H Malaysia and Cameroon, but the current year included lower seismic spending in Republic of the Congo. Other exploration costs were $11.9 million more in 2011 than 2010 mostly due to higher office costs allocable to exploration activities in Brunei, Indonesia and Iraq, and an exploration well drilling penalty in Southern Alberta. Undeveloped leasehold amortization expense was $10.2 million higher in 2011 than 2010 mostly due to lease costs associated with concessions in the Kurdistan region of Iraq, but partially offset by slightly lower amortization costs in 2011 for Eagle Ford Shale leases in South Texas and the Montney area of Western Canada.

Dry hole expense was $35.2 million lower in 2010 than in 2009 despite a 50% increase in spending for exploratory drilling. Dry hole expense in the U.S. was lower in 2010 mostly due to deferral of planned Gulf of Mexico drilling due to the moratorium imposed by the Federal government following the April 2010 blowout and oil spill at the Macondo well owned by other companies. Malaysian operations had lower dry hole expense in 2010 due to more successful exploratory drilling results and favorable adjustments to final costs on prior-year wells. Dry holes in the U.K. in 2010 primarily related to a decision to expense a well drilled in 2008 for which studies in 2010 indicated a lack of economical development options based on current pricing levels. Dry hole expense in Republic of the Congo was higher in 2010 than 2009 due to drilling more unsuccessful wells in the MPS block in the later year. Dry hole expense in 2010 in other foreign areas was less than in 2009 primarily due to an unsuccessful well offshore Australia in 2009. G&G expenses were $24.6 million higher in 2010 than 2009. Areas of higher spending on seismic in the 2010 year included the Eagle Ford Shale area of South Texas, the MPN and MPS blocks offshore Republic of the Congo, and offshore Malaysia. These higher G&G costs in 2010 were somewhat offset by lower spending in the Tupper area of Western Canada and offshore Suriname. Other exploration costs in 2010 were $12.9 million above 2009 levels primarily due to higher administrative costs for operations in Suriname, Indonesia and Australia in 2010. Undeveloped leasehold amortization expense rose $24.8 million in 2010 compared to 2009, primarily due to higher amortization associated with lease acquisition costs in the Eagle Ford Shale area of South Texas, partially offset by less amortization expense in 2010 following sanction of development at the Tupper West property in August 2009.

The Company recorded a $368.6 million impairment charge in 2011 to reduce the carrying value of the Azurite oil field, offshore Republic of the Congo, to fair value. The impairment charge at Azurite was necessitated by a reduction in the field s proved oil reserves at year-end 2011 due to poor well performance. An impairment charge of $5.2 million was recorded in 2009 to write-off the remaining costs of a poorly performing natural gas field in the Gulf of Mexico.

Depreciation, depletion and amortization expense for exploration and production operations totaled $969.7 million in 2011, $1,005.0 million in 2010 and $775.8 million in 2009. The $35.3 million decrease in 2011 compared to 2010 was primarily attributable to lower overall levels of hydrocarbon volumes sold, somewhat offset by a slightly higher per-barrel depreciation rate based on a change in the mix of production between 2011 and 2010. The $229.2 million increase in 2010 compared to 2009 was primarily caused by higher overall volumes of oil and natural gas sold during 2010. Additionally, a higher proportion of 2010 production was derived from fields brought onstream in recent years under a higher-cost development environment.

The exploration and production business recorded expenses of $36.8 million in 2011, $31.1 million in 2010 and $25.5 million in 2009 for accretion on discounted abandonment liabilities. Because the abandonment liability 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 $5.7 million increase in accretion costs in 2011 compared to 2010 was attributable to a higher number of wells drilled in the current year in the Eagle Ford Shale and Montney areas and higher overall future estimated abandonment cost liabilities for Gulf of

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Mexico wells and synthetic oil operations at Syncrude. The $5.6 million increase in accretion expense in 2010 compared to 2009 was due to additional wells drilled during the later year in several geographical areas and higher estimated abandonment costs for offshore operations in Malaysia and for Syncrude synthetic oil operations.

The effective income tax rate for exploration and production continuing operations was 53.8% in 2011, 41.7% in 2010 and 40.8% in 2009. The effective tax rate was significantly higher in 2011 than 2010 due to no tax benefit recorded on the impairment charge for the Azurite field and higher exploration and administrative expenses in certain foreign tax jurisdictions where no tax benefit can be currently recognized due to lack of sufficient revenue to realize a current or future benefit. Income tax expense in 2011 was reduced by a $25.6 million benefit for expenses incurred in prior years in Block P, Malaysia. It was determined during 2011 that these expenses in Block P are deductible against taxable income generated in Block K Malaysia. Also, in 2011, the U.K. government enacted a 12% supplemental tax on oil and gas company profits in that country. This tax increase raised the Company s tax expense in 2011 by $14.5 million, primarily to increase the recorded balance for deferred income taxes that will be paid in future years at the new higher rate. The effective tax rate is now 62% in the U.K. The overall effective income tax rate was slightly higher in 2010 than 2009 mostly due to tax barrels owed the government of Republic of the Congo under the production sharing agreement covering the Azurite field. More tax barrels were owed the government due to higher Azurite production levels in 2010. The effective tax rates in all three years exceeded the U.S. statutory tax rate of 35.0% due to higher overall foreign tax rates and exploration and other expenses in areas where current tax benefits cannot be recorded by the Company. Tax jurisdictions with no current tax benefit on expenses primarily include certain non-revenue generating areas in Malaysia, Suriname, Australia, Indonesia, Brunei, Cameroon and the Kurdistan region of Iraq. Each main exploration area in Malaysia is currently considered a distinct taxable entity and expenses in certain areas may not be used to offset revenues generated in other areas. No tax benefits have thus far been recognized for costs incurred for Block H, offshore Sabah, and Blocks PM 311/312, offshore Peninsula Malaysia.

At December 31, 2011, 34.5 million barrels of the Company s U.S. proved oil reserves and 40.2 billion cubic feet of U.S. proved natural gas reserves were undeveloped. More than 77% of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company s Eagle Ford Shale operations in South Texas. Further drilling and facility construction are generally required to move the undeveloped reserves in the Eagle Ford Shale area to developed. In the Western Canadian Sedimentary Basin, total proved undeveloped natural gas reserves totaled 211.8 billion cubic feet, with the migration of these reserves, primarily in the Tupper and Tupper West areas, dependent on both development drilling and completion of processing and transportation facilities. In Block K Malaysia, all oil reserves of 14.7 million barrels for the Kakap field are undeveloped pending completion of facilities and development drilling directed by another company. Additionally, the Kikeh field had undeveloped oil reserves of 28.0 million barrels, which are subject to further development drilling before being moved to developed. Also in Malaysia, there were 98.3 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2011, which were held under this category pending completion of development drilling and facilities. The deepwaters of the Gulf of Mexico and the Schiehallion field in the U.K. North Sea accounted for additional proved undeveloped reserves of 9.2 million and 17.4 million equivalent barrels of oil, respectively, at December 31, 2011. On a worldwide basis, the Company spent approximately $1.88 billion in 2011, $1.27 billion in 2010 and $1.34 billion in 2009 to develop proved reserves.

Refining and Marketing The Company s refining and marketing (R&M) operations generated earnings from continuing operations of $190.3 million in 2011, $130.6 million in 2010 and $45.0 million in 2009. The R&M earnings improvement of $59.7 million in 2011 compared to 2010 was mostly attributable to a $0.042 per gallon improvement in retail fuel marketing sales margin in the U.S. and higher profits on merchandise sales at U.S. retail stations in 2011. The R&M earnings increase of $85.6 million in 2010 compared to 2009 was driven primarily by a $0.03 per gallon improvement in sales margin for retail fuel, partially offset by lower refining margins in the U.K. in 2010 compared to the prior year.

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The Company has announced its intention to divest its U.K. refining and marketing operations in 2012. The Meraux, Louisiana and Superior, Wisconsin refineries were sold in 2011 and are reported as discontinued operations.

The Company s United States R&M operations generated earnings from continuing operations of $223.6 million in 2011, $165.3 million in 2010 and $65.5 million in 2009. U.S. R&M operations include two ethanol production facilities, along with retail and wholesale fuel marketing operations. The $58.3 million increase in U.S. income in 2011 compared to 2010 was primarily attributable to more than a $0.04 per gallon improvement in retail fuel margin partially offset by a reduction in gallons sold. Additionally, the Company had higher profits in 2011 on the sale of merchandise in this business. Total fuel sales volumes per station at Company operated sites in the U.S. averaged about 277,700 gallons per month during 2011, down 9% from the prior year. U.S. profits in 2011 included higher income from the Company s ethanol production facilities compared to 2010. The Hankinson plant operated for both years while the Hereford plant was open for most of 2011 only. Corn costs were higher in 2011 compared to 2010, but this increase was essentially offset by higher sales prices for ethanol and by-products, dried distillers grains and wet distillers grains, in the current year.

United States R&M profits from continuing operations increased $99.8 million in 2010 compared to 2009. The 2010 increase was due to a $0.03 per gallon higher fuel margin compared to 2009 in the retail marketing business. The retail marketing business had slightly lower volumes sold in 2010 compared to 2009. Fuel margins in the retail chain were hurt in 2009 by both lower demand for gasoline and diesel due to the weak economy and generally rising wholesale fuel costs caused by crude oil prices that rose gradually during the year.

United States refined product sales volumes (including discontinued operations) averaged 420,737 barrels per day in 2011, compared to 450,100 barrels per day in 2010 and 432,700 barrels per day in 2009. The decrease in 2011 was primarily due to the sale of the two U.S. refineries near the end of September 2011, plus lower gasoline volumes sold through the U.S. retail marketing business. The sales volume increase in 2010 compared to 2009 was mostly attributable to more finished products produced at the U.S. refineries compared to the prior year. Additionally 2010 included a full year of ethanol production from the Hankinson facility acquired in October 2009, compared to only three months of ethanol production in 2009. The retail marketing business added 29 stations in 2011, 51 stations in 2010 and 23 stations in 2009. The U.S. retail marketing network included 1,128 stations at year-end 2011.

United Kingdom R&M operations incurred a loss of $33.3 million in 2011 compared to losses of $34.7 million in 2010 and $20.5 million in 2009. The loss in 2011 decreased from 2010 by $1.4 million, primarily caused by slightly better refining margins in 2011 and higher throughput volumes in 2011 due to a two-month plant wide turnaround at the Milford Haven, Wales refinery in 2010. The loss in 2010 was higher than 2009 for U.K. R&M operations primarily due to weaker margins at the Milford Haven refinery and lower crude oil throughput caused by the refinery undergoing approximately a two-month plant-wide turnaround during 2010. U.K. refining margin was hurt by weak demand during the two-year period of 2009 and 2010. Soft demand for refined products in the U.K. and Western Europe led to an industry-wide oversupply of gasoline and diesel products in the area.

Unit margins in the United Kingdom averaged $(0.67) per barrel in 2011, $(1.47) per barrel in 2010 and $(0.28) per barrel in 2009. Overall refined product sales volumes in the U.K. averaged 135,697 barrels per day in 2011, up 57% compared to 2010. The increase in sales volumes in 2011 was primarily due to downtime associated with a turnaround at the Milford Haven refinery in 2010. Sales volumes of refined products in the U.K. declined 16% to 86,657 barrels per day in 2010 compared to 2009, essentially due to the same refinery turnaround in 2010.

Corporate The after-tax costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and unallocated corporate overhead, were $75.1 million in 2011, $157.9 million in 2010 and $23.0 million in 2009.

The net cost of corporate activities in 2011 was $82.8 million lower than in 2010, primarily due to more favorable effects of foreign currency exchange, which was associated with transactions denominated in currencies other than the respective operation s predominant functional currency. The effect of foreign currency exchange after taxes was a gain of $20.7 million in 2011 compared to a loss after taxes of $58.1 million in 2010. The U.S. dollar generally strengthened against the Malaysian ringgit in 2011 after having weakened against this currency during 2010. The stronger U.S. currency in 2011 reduced the dollar cost of tax liabilities in Malaysia which are payable in the local currency. The Malaysian operation s functional currency is the U.S. dollar. Foreign currency transaction effects in the U.K. were also favorable in 2011 compared to the prior year. The corporate area also benefited in 2011 from higher interest income of $3.2 million compared to 2010, principally due to higher levels of invested cash earning interest during the current year. Net interest expense, after capitalization of finance-related costs to development projects, was $6.0 million higher in 2011 than 2010. This unfavorable variance was principally due to interest charged on certain tax assessments in Canada and lower amounts of interest capitalized to development projects in the latest year, primarily at the Tupper West area development in Western Canada where gas production started up in the first quarter of 2011. Administrative expenses associated with corporate activities were also higher in 2011 compared to 2010, primarily associated with additional costs for compensation and professional services.

The net cost of corporate activities rose $134.9 million in 2010 compared to 2009. The most significant variance related to the effects of foreign currency exchange. The Company had after-tax losses from foreign currency exchange of $58.1 million in 2010, while 2009 had after-tax gains of $33.3 million. The foreign currency exchange loss in 2010 was primarily associated with a stronger Malaysian ringgit compared to the U.S. dollar. This led to costs associated with higher recorded future income tax liabilities, which are required to be paid in local currency. Foreign currency exchange losses were also experienced in the U.K. during 2010 caused by a stronger U.S. dollar compared to the British pound sterling. This led to higher costs for U.S. dollar denominated liabilities owed by the Company s U.K. refining and marketing business, which has a sterling functional currency. Additionally, 2009 benefited from interest income of $42.0 million associated with a recovery of Federal royalties previously paid on certain deepwater Gulf of Mexico oil and natural gas production. Net interest expense, after capitalization of finance-related costs to development projects, was $10.3 million higher in 2010 than 2009 mostly due to lower interest capitalized on oil and natural gas development projects during 2010. Corporate activities had higher administrative and depreciation expenses in 2010 than in 2009 of $14.9 million and $2.0 million, respectively, compared to 2009. The increase in administrative expense in 2010 was primarily associated with higher employee compensation costs. Income taxes associated with corporate activities in 2010 were significantly favorable to 2009 due to higher net pretax costs in the later year.

Discontinued Operations On September 30, 2011, the Company sold its Superior, Wisconsin refinery and related assets for $214 million, plus certain capital expenditures between July 25, 2011 and the date of closing and the fair value of all associated hydrocarbon inventories at these locations. On October 1, 2011, the Company sold its Meraux, Louisiana refinery and related assets for $325 million, plus the fair value of associated hydrocarbon inventories. The Company began to account for the Superior, Wisconsin and Meraux, Louisiana refineries and associated marketing assets as discontinued operations beginning in the third quarter 2011. All prior years presented have been reclassified to conform to this presentation of the Superior and Meraux operating results as discontinued operations.

Income from discontinued operations was $131.8 million in 2011, including operating profits of $113.1 million and an after-tax gain on sale of the two U.S. refineries of $18.7 million. The after-tax gain from disposal of the two refineries included a gain on the Superior refinery (including associated inventories) of $77.6 million and a loss on the Meraux refinery (including associated inventories) of $58.9 million. The net gain on disposal was based on the selling prices of the refineries, plus the sales of all associated inventories at fair value, which was significantly above the last-in, first-out carrying value of the inventories sold. Operating profits in 2011 of $113.1 million were significantly better than the 2010 operating profits of $18.5 million due to much stronger refining margins in 2011.

Income from discontinued operations associated with the two U.S. refineries was a profit of $18.5 million in 2010 compared to income of $26.7 million in the 2009 period. The 2010 decline in results was primarily due to lower refining margins, and a nonrecurring income item in 2009 related to insurance settlements for Hurricane

Katrina. The 2010 results benefited from higher crude oil throughput volumes compared to 2009. The 2009 results from discontinued operations also included income from Ecuador properties of $97.1 million, which primarily arose from a gain on disposal of $103.6 million.

Capital Expenditures

As shown in the selected financial data on page 23 of this Form 10-K report, capital expenditures from continuing operations, including exploration expenditures, were $2.90 billion in 2011 compared to $2.33 billion in 2010 and $2.09 billion in 2009. These amounts excluded capital expenditures of $48.1 million in 2011, $117.3 million in 2010 and $113.3 million in 2009 related to discontinued operations, which was primarily associated with two U.S. petroleum refineries sold during 2011. Capital expenditures included $371.7 million, $184.3 million and $182.0 million, respectively, in 2011, 2010 and 2009 for exploration costs that were expensed. Capital expenditures for exploration and production continuing operations totaled $2.77 billion in 2011, $2.03 billion in 2010 and $1.81 billion in 2009, representing 96%, 87% and 86%, respectively, of the Company s total capital expenditures from continuing operations for these years. Capital expenditures in 2011 for the E&P business included $279.3 million for undeveloped lease acquisitions, $23.5 million associated with a contract revision at the Azurite field, $560.2 million of exploration activities and $1.91 billion for development programs. Lease acquisitions were primarily associated with activities in the Eagle Ford Shale area of South Texas and exploration concessions in the Kurdistan region of Iraq. Exploration costs principally related to exploratory drilling at resource plays in North America, including the Eagle Ford Shale in South Texas and new areas in Southern Alberta, plus wildcat drilling activities in Brunei, Indonesia and Suriname. Development projects in 2011, primarily included spend of $572.2 million at the Tupper West and Tupper natural gas areas in Western Canada; $153.7 million for Seal heavy oil area activities; $339.6 million for the Kikeh field in Malaysia; $236.4 million for Sarawak SK Blocks 309/311 oil and gas projects offshore Malaysia; $115.7 million for the Kakap field in Block K, offshore Sabah Malaysia; $219.7 million for work in the Eagle Ford Shale; and $73.9 million for synthetic oil operations at Syncrude.

E&P capital expenditures in 2010 included $242.8 million for acquisition of undeveloped leases, which primarily included leases acquired in the Eagle Ford Shale area of South Texas and in the Tupper West area in Western Canada, $470.0 million for exploration activities, $1.30 billion for development projects, and $22.0 million for acquisition of proved properties in Canada. Development expenditures included $524.7 million at the Tupper and Tupper West areas; $46.8 million for deepwater fields in the Gulf of Mexico; $166.8 million for Kikeh; $160.4 million for natural gas and oil development activities in SK Blocks 309/311; $58.1 million for Kakap; $63.2 million for Syncrude; $84.9 million for Western Canada heavy oil projects; $126.5 million for development of the Azurite field in Republic of the Congo; and $21.2 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland. Exploration and production capital expenditures are shown by major operating area on page F-50 of this Form 10-K report.

Refining and marketing capital expenditures for continuing operations totaled $122.3 million in 2011, $290.1 million in 2010 and $263.4 million in 2009. These amounts represented 4%, 12% and 13% of capital expenditures of the Company in 2011, 2010 and 2009, respectively. Total refining and marketing capital expenditures above excluded $48.1 million, $117.3 million and $112.5 million in 2011, 2010 and 2009, respectively, for U.S. refineries sold in 2011, which are now classified as discontinued activities. Refining capital spending for discontinued operations during the three years primarily included costs at Meraux to reduce benzene production, construct a new laboratory, revamp the distillate hydrotreater and expand crude oil storage capacity, and at Superior to meet compliance with ultra-low sulfur diesel and Mobile Source Air Toxic requirements. Refining spend within continuing operations totaled $14.7 million in 2011, $59.8 million in 2010 and $94.9 million in 2009. These expenditures related to the Milford Haven, Wales refinery, and in 2011 principally included minor capital improvements, while the majority of 2010 and 2009 spend related to costs to expand crude oil throughput capacity at Milford Haven to 135,000 barrels per day. Marketing expenditures amounted to $84.9 million in 2011, $185.4 million in 2010 and $77.1 million in 2009. Marketing capital spending in 2011 was principally related to new station construction in the U.S. market. Marketing capital expenditures in 2010 were primarily associated with building new retail stations and acquiring land for new station sites in the U.S., while marketing capital expenditures in 2009 were primarily associated with new station builds and other improvements within the U.S. retail gasoline station network. The Company added 29 stations within its U.S. retail gasoline network in 2011, after adding 51 in 2010 and 23 in 2009. Capital expenditures related to ethanol operations in the U.S. totaled $22.7 million in 2011, $44.9 million in 2010 and $91.4 million in 2009. The Company spent $40.0 million in 2010 to acquire an unfinished ethanol production facility in Hereford, Texas. Construction of the Hereford facility was completed at an added cost of about $25.1 million and the facility commenced operation near the end of the first quarter 2011. In 2009, the Company spent $92.0 million to acquire an ethanol production facility and inventory in Hankinson, North Dakota. The Hankinson ethanol plant was financed with an $82.0 million nonrecourse loan from the seller and a cash payment of $10.0 million. The nonrecourse loan was repaid in 2010. See Note D of the consolidated financial statements for further details about these acquisitions.

Cash Flows

Operating activities Cash provided by operating activities was $2.15 billion in 2011, $3.13 billion in 2010 and $1.86 billion in 2009. Cash provided by operating activities included cash from discontinued operations of $145.5 million in 2011, $100.5 million in 2010 and $94.4 million in 2009. Cash provided by continuing operations in 2011 was $1.03 billion less than 2010 primarily due to timing of cash collected and disbursed associated with changes in other working capital balances. Cash was primarily used to pay down accounts payable for crude oil feedstocks at formerly owned U.S. petroleum refineries and to pay income taxes in the U.S and Malaysia. Cash provided by continuing operations in 2010 was $1.26 billion more than 2009 primarily due to a drawdown of working capital other than cash in the current year and higher income from continuing operations. The working capital reduction in 2010 included cash receipts of $286.4 million related to recovery of federal royalties and associated interest income. Income associated with the royalty recovery was recorded in 2009, but the cash proceeds were collected in early 2010. Cash provided by operating activities was reduced by expenditures for abandonment of oil and gas properties totaling $24.7 million in 2011, $36.5 million in 2010 and $48.7 million in 2009.

Investing activities Cash proceeds from property sales classified as continuing operations were $27.8 million in 2011, $2.2 million in 2010 and $1.6 million in 2009. The 2011 proceeds primarily related to sale of gas storage assets in Spain. In 2011, the Company generated cash of $950.0 million from sale of two U.S. refineries and associated marketing assets, including liquid inventories. The U.S. refineries operating results and cash flow have been classified as discontinued operations in the Company s consolidated financial statements. Other investing activities for discontinued operations included capital expenditures of $48.1 million in 2011, $117.3 million in 2010 and $113.3 million in 2009. Additionally, the two U.S. refineries which were sold used cash of $1.5 million in 2011, $37.5 million in 2010 and $10.2 million in 2009 for maintenance turnarounds. During 2009, the Company generated cash of $78.9 million from the sale of its 20% working interest in Block 16 in Ecuador. Operating results and cash flows associated with Ecuador operations have also been classified as discontinued operations. Property additions and dry hole costs for continuing operations used cash of $2.62 billion in 2011, $2.24 billion in 2010 and $1.88 billion in 2009. Cash used to pay for capital expenditures increased each year compared to the prior year, with these variances essentially in line with changes in capital expenditures in each year. Cash of $1.69 billion, $2.39 billion and $2.53 billion was spent in 2011, 2010 and 2009, 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 $1.77 billion in 2011, $2.55 billion in 2010 and $2.17 billion in 2009. Cash of $5.4 million in 2011, $61.4 million in 2010 and $19.3 million in 2009 was used for turnarounds at the Milford Haven, Wales, refinery and Syncrude. The higher spend in 2010 was attributable to a plant-wide turnaround at Milford Haven.

Financing activities During 2011 and 2010, the Company used available cash flow to repay $340.0 million and $414.0 million, respectively, of debt. During 2009, the Company borrowed $243.5 million under debt agreements primarily to fund a portion of the Company s development capital expenditures. The debt reduction in 2011 was accomplished with proceeds from sale of the two U.S. refineries. In 2009, the Company paid $10.0 million to partially finance the acquisition of the Hankinson, North Dakota, ethanol plant; the remaining $82.0 million acquisition price was financed with a seller-provided nonrecourse loan. This nonrecourse loan was fully

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repaid in 2010. Cash proceeds from stock option exercises and employee stock purchase plans, including income tax benefits on stock options, amounted to $20.4 million in 2011, $54.7 million in 2010 and $16.9 million in 2009. In 2011, the Company used cash of $7.9 million for fees and other expenses associated with renewing its primary $1.5 billion committed credit facility that expires in June 2016. Also, in 2011 and 2010, cash of $8.0 million and $5.2 million, respectively, was used to pay statutory withholding taxes on stock-based incentive awards that vested with a net-of-tax payout. Cash used for dividends to stockholders was $212.8 million in 2011, $201.4 million in 2010 and $190.8 million in 2009. The Company maintained its $1.10 per share annualized dividend rate in 2011. It had previously raised its annualized dividend rate from $1.00 per share to $1.10 per share beginning in the third quarter of 2010.

Financial Condition

Year-end working capital (total current assets less total current liabilities) totaled $622.7 million in 2011 and $619.8 million in 2010. The current level of working capital does not fully reflect the Company s liquidity position as the carrying value for inventories under last-in, first-out accounting was $580.2 million below fair value at December 31, 2011. Cash and cash equivalents at the end of 2011 totaled $513.9 million compared to $535.8 million at year-end 2010.

Long-term debt decreased by $689.8 million during 2011 and totaled $249.6 million at year-end 2011, representing 2.8% of total capital employed. The reduction in long-term debt in 2011 included a $350.0 million reclassification of notes payable to a current liability. These notes mature in May 2012 and the Company is evaluating whether to sell replacement debt instruments. Long-term debt decreased by $413.8 million in 2010. Stockholders equity was $8.78 billion at the end of 2011 compared to $8.20 billion a year ago and $7.35 billion at the end of 2009. A summary of transactions in stockholders equity accounts is presented on page F-8 of this Form 10-K report.

Other changes in Murphy s year-end 2011 balance sheet compared to 2010 included an $84.5 million reduction in the balance of short-term investments in Canadian government securities with maturities greater than 90 days at the time of purchase. The total investment in these Canadian government securities was $532.1 million at year-end 2011 and $616.6 million at year-end 2010. These slightly longer-term investments were purchased in each year because of a tight supply of shorter-term securities available for purchase in Canada. An $86.9 million increase in accounts receivable in 2011 was primarily caused by higher sales prices for crude oil and finished products sold, and higher natural gas sales volumes sold on credit terms by the Company, but partially offset by the sale of U.S. refineries in 2011, which effectively reduced refined products volumes sold under credit arrangements in the U.S. in 2011. Inventory values were $95.6 million less at year-end 2011 than in 2010 mostly due to lower levels of crude oil and refined products held in storage within downstream operations in the later year due to sale of two refineries in the U.S., but partially offset by higher costs for unsold crude oil production held in inventory in the current year. Prepaid expenses increased $5.2 million in 2011 primarily due to prepaid income taxes in the U.S. at year-end 2011. Short-term deferred income tax assets were $6.9 million higher at year-end 2011 compared to 2010 due mostly to more current temporary differences for expense deductions within U.K. downstream operations. Net property, plant and equipment increased by $107.3 million in 2011 as a significant level of property additions during the year exceeded the amounts of depreciation, amortization and impairment expenses recorded during 2011. Goodwill decreased $1.0 million in 2011 due to a weaker Canadian dollar exchange rate versus the U.S. dollar. Deferred charges and other assets decreased $98.4 million mostly due to no deferred turnaround costs and other noncurrent assets remaining for the Meraux and Superior refineries following their sale in 2011. Current maturities of long-term debt at year-end 2011 was $350.0 million higher than at the prior year-end due to a reclassification of $350.0 million of outstanding notes payable to current based on their upcoming maturity in May 2012. Accounts payable decreased by $296.9 million at year-end 2011 compared to 2010 primarily due to lower amounts owed for purchased crude oil feedstocks following the sale of the U.S. refineries in 2011. Income taxes payable was $157.0 million lower at year-end 2011 than at the end of 2010, primarily due to less U.S. income tax liabilities owed in 2011. Other taxes payable at year-end 2011 was $37.4 million lower than in 2010 mostly due to less value added taxes owed by the U.K. downstream operations and lower excise taxes owed by U.S. downstream operations. Other accrued liabilities increased by $30.1 million at year-end 2011 mostly due to higher amounts owed for compensation and other operating costs. The current portion of deferred income tax liabilities increased $5.3 million in 2011 due to higher short-term temporary differences for tax deductions in Canada in the current year. Noncurrent deferred income tax liabilities were $17.9 million higher at year-end 2011 mostly due to accelerated tax depreciation associated with the Company s 2011 capital expenditures, primarily in Malaysia and Canada. The liability associated with future asset retirement obligations increased by $60.3 million at year-end 2011 mostly due to higher estimated future costs to retire assets in the U.S. and Canada. Deferred credits and other liabilities were $43.6 million more in 2011 compared to 2010 mostly due to higher noncurrent liabilities associated with postemployment benefit plans in the current year.

Murphy had commitments for future capital projects of approximately $1.85 billion at December 31, 2011, including $839.5 million for field development and future work commitments in Malaysia, $149.7 million for costs to develop deepwater Gulf of Mexico fields, $124.5 million for work in the Eagle Ford Shale and $127.5 million for future work commitments offshore Brunei.

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, 2011, the Company had access to a long-term committed credit facility in the amount of $1.5 billion. There were no outstanding borrowings under the committed credit facility at year-end 2011. 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 2016. At December 31, 2011, the Company had uncommitted bank credit lines of approximately $400.0 million, but no borrowings were outstanding under these lines. The long-term debt to total capital ratio was 2.8% at year-end 2011. In September 2009, 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 may use this shelf registration, if needed, in future years to raise debt or equity capital to fund operational requirements. This shelf registration expires in September 2012. Current financing arrangements are set forth more fully in Note F to the consolidated financial statements. Based on the anticipated level of capital expenditures the Company has budgeted during 2012, the Company anticipates that it will need to borrow under its long-term debt facility during 2012. The Company s ratio of earnings to fixed charges was 15.6 to 1 in 2011, 14.6 to 1 in 2010 and 14.5 to 1 in 2009.

Cash and invested cash are maintained in several operating locations outside the United States. At December 31, 2011, cash, cash equivalents and cash temporarily invested in Canadian government securities held outside the U.S. included approximately $608 million in Canada, $94 million in the U.K. and $83 million in Malaysia. In certain cases, the Company could incur 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 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 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. Virtually all operations of the Company are affected by laws and regulations covering environmental, health and safety matters. Compliance with existing and anticipated environmental regulations affects Murphy s overall cost of business, including capital costs to construct,

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maintain and upgrade equipment and facilities, and operating costs for ongoing environmental compliance. Murphy s competitive position may be impacted to the extent that regulatory requirements with respect to a particular production technology may give rise to costs that competitors might not bear. Environmental regulations have historically been subject to frequent change by regulatory authorities and these are expected to continue to evolve in the foreseeable future. The Company is unable to predict the ongoing cost of complying with these laws and regulations or the future impact of such regulations on its operations. 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 Murphy 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.

Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations, and such capital expenditures were $103.7 million in 2011 and are projected to be $74.7 million in 2012. The sale of U.S. refineries in 2011 will reduce future capital expenditures required to comply with environmental laws and regulations.

The most significant of those laws and the corresponding regulations affecting Murphy s operations are:

- The U.S. Clean Air Act, which regulates air emissions
- The U.S. Clean Water Act, which regulates discharges into U.S. waters
- The U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which addresses liability for hazardous substance releases
- The U.S. Federal Resource Conservation and Recovery Act (RCRA), which regulates solid waste and hazardous waste treatment, storage and disposal.
- The U.S. Federal Oil Pollution Act of 1990 (OPA90), which addresses liability for discharges of oil into navigable waters of the United States
- The U.S Safe Drinking Water Act, which regulates disposal of wastewater into underground injection wells
- The Federal Water Pollution Control Act of 1972 (FWPCA) also addressing discharge of pollutants into navigable waters
- The Department of the Interior governing offshore oil and gas operations.
- The European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH)
- The European Union Trading Directive resulting in European Emissions Trading Scheme

These laws and their associated regulations establish limits on emissions and standards for quality of air, water and solid waste discharges. They also generally require permits for new or modified operations. Many states and foreign countries where the Company operates also have or are in the process of developing similar statutes and regulations governing air and water as well as the characteristics and composition of refined products, which in some cases impose or could impose additional and more stringent requirements. Murphy is also subject to certain acts and regulations, including legal and administrative proceedings, governing remediation of wastes or oil spills from current and past operations, which include but may not be limited to leaks from pipelines, underground storage tanks and general environmental operations. Murphy is actively engaged in the legislative and regulatory process, both nationally and internationally, in response to climate change issues and environmental and health related matters.

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Murphy s Environmental, Health, and Safety Committee, a standing committee of the Board of Directors, was created to oversee and monitor the Company s environmental, health, and safety (EHS) policies and practices. In February 2009, the Board approved a worldwide environmental, health, and safety policy (the EHS Policy), which is available on the Company s Web site. In addition to requiring that the Company comply with all applicable EHS laws and regulations, the EHS Policy includes a directive that the Company will continue to minimize the impact of its operations, products and services on the environment by implementing economically feasible projects that promote energy efficiency and use natural resources effectively.

CERCLA

CERCLA commonly referred to as the Superfund Act, and comparable state statutes, primarily address historic contamination and impose joint and several liability upon Potentially Responsible Parties (PRP), without regard to fault or the legality of the original act that contributed to the release of a hazardous substance into the environment. Cleanup of contaminated sites is the responsibility of the owners and operators of the sites that released, disposed, or arranged for the disposal of the hazardous substances found at the site. CERCLA requires reporting to the National Response Center for releases to the environment of substances defined as hazardous or extremely hazardous if the released quantities exceed an EPA established reportable level. CERCLA also authorizes the U.S. Environmental Protection Agency (EPA) and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible persons. In the course of ordinary operations, the Company generates waste that falls within CERCLA s definition of a hazardous substance. Murphy may be jointly and severally liable under CERCLA for all or part of the costs required to remediate sites at which such hazardous substances have been disposed of or released into the environment.

The EPA currently considers Murphy to be a PRP at one Superfund site. The potential total cost to all parties to perform necessary remedial work at this site may be substantial. However, based on current negotiations and available information, the Company believes that it is a de minimis party as to ultimate responsibility at the Superfund site and as such, it has not recorded a liability for remedial costs. The Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at this site or other Superfund sites. The Company believes that its share of the ultimate costs to remediate this Superfund site will be immaterial and will not have a material adverse effect on net income, financial condition or liquidity in a future period.

Waste

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. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws Murphy 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. While some of these historical properties are in various stages of negotiation, investigation, and/or cleanup, Murphy is investigating the extent of any such liability and the availability of applicable defenses, including state funding for remediation, and believe costs related to these sites will not have a material adverse affect on its net income, financial condition or liquidity in a future period. Although certain environmental expenditures are likely to be recovered from other sources, no assurance can be given that future recoveries from these sources will occur. Therefore, the Company has not recorded a benefit for likely recoveries as of December 31, 2011.

RCRA and comparable state statutes govern the management and disposal of solid wastes, with the most stringent regulations applicable to treatment, storage or disposal of hazardous wastes. Murphy generates non-hazardous solid wastes that are subject to the requirements of RCRA and comparable state statutes. The Company s operating sites also incur costs to handle and dispose of hazardous waste and other chemical substances. The costs of disposing of these substances are expensed as incurred and are not expected to have a material adverse effect on net income, financial condition or liquidity in a future period. However, it is possible that additional wastes, which could include wastes currently generated during operations, will in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly disposal requirements than are non-hazardous wastes. Such changes in the regulations could result in additional capital expenditures and operating expenses.

Water

Under OPA90, owners and operators of tankers, owners and operators of onshore facilities and pipelines, and lessees or permittees of an area in which an offshore facility is located are liable for removal and cleanup costs of oil discharges into navigable waters of the United States. The Company is not aware of OPA90 claims made against Murphy.

Each Murphy offshore facility in the Gulf of Mexico has in place an Emergency Evacuation Plan (EEP) and all such facilities are covered by an Oil Spill Response Plan (OSRP). In the event of an explosion, personnel would be evacuated immediately in accordance with the EEP. The appropriate OSRP would be activated if needed. In the event of an oil spill or containment event, the appropriate OSRP and Containment Plan would be executed as needed. The EEP is approved by the U.S. Coast Guard (USCG) and the OSRP and Containment Plan are approved by the Bureau of Ocean Energy Management (BOEM). The Company also has comprehensive emergency and spill response plans for offshore facilities in international waters.

Murphy s OSRP utilizes a consortium of seasoned and well equipped contract service companies to provide response equipment and personnel. One company has been contracted to provide spill containment and recovery equipment, including skimmers, boom, and vessels such as fast response boats and high volume open sea skimmer barges. This company has hired other companies to store and maintain response equipment and provide certified tanks and barges. Murphy is a founding member of Marine Preservation Association, which provides access to Marine Spill Response Corporation assets to support marine spills in the Gulf of Mexico and other offshore areas. Additionally, Murphy has an agreement with another company to provide aerial dispersant spraying services, and has further contracted with another company to utilize their equipment for oil containment should a well blowout occur.

The Federal Water Pollution Control Act of 1972 (FWPCA) imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA imposes substantial potential liability for the costs of removal, remediation and damages. Murphy maintains wastewater discharge permits for its facilities where required pursuant to the FWPCA and comparable state laws. Murphy has also applied for all necessary permits to discharge storm water under such laws. The Company believes that compliance with existing permits and foreseeable new permit requirements will not have a material adverse effect on net income, financial condition or liquidity in a future period.

Murphy utilizes hydraulic fracturing technology for its exploration and production activities in Canada and the U.S. Murphy is actively engaged in exploration and production in the Eagle Ford Shale play in South Texas. On January 31, 2012, the Texas Railroad Commission finalized a rule that requires oil and gas operators to publicly disclose the chemicals and amount of water used in hydraulic fracturing of wells.

Air

Murphy s U.S. operations are subject to the Federal Clean Air Act and comparable state and local statutes. The Company believes that its operations are in substantial compliance with these statutes in all states in which it operates. Amendments to the Federal Clean Air Act enacted in 1990 required most refining operations in the U.S. to incur capital expenditures in order to meet air emission control standards developed by the EPA and state environmental agencies.

Under the EPA s Clean Air Act authority, the National Petroleum Refinery (NPR) Initiative (Global Consent Decree) was used by the EPA to undertake at virtually all U.S. refineries an investigation of four marquee compliance areas, including: (i) New Source Review/Prevention of Significant Deterioration for fluidized catalytic cracking units, heaters and boilers; (ii) New Source Performance Standards for flares, sulfur recovery units, fuel gas combustion devices (including heaters and boilers); (iii) Leak Detection and Repair requirements; and (iv) Benzene National Emissions Standards for Hazardous Air Pollutants. Murphy began negotiations with the EPA in 2005, but was interrupted by the events of Hurricane Katrina. The states of Louisiana and Wisconsin are both parties to the NPR. Negotiations with EPA resumed in 2007 and were essentially completed in 2010. Under the Global Consent Decree, the Company paid a fine of $1.25 million and committed to certain future capital improvements. The Company sold its two U.S. refineries in 2011.

The European Union has adopted an Emissions Trading Scheme in response to the Kyoto Protocol in order to achieve reductions in greenhouse gas emissions. Murphy s refinery at Milford Haven, Wales, currently has the most exposure to these requirements and may require purchase of emission allowances to maintain compliance with environmental permit requirements. These environmental expenditures are expensed as incurred. In 2011, Murphy was notified by the Environment Agency (EA) that it failed to surrender proper emission allowances, which Murphy self-reported to the EA in 2010. The Company is evaluating all available options regarding this matter.

Climate Change

Currently, various national and international legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of discussion or implementation. These include a promulgated EPA regulation, Mandatory Reporting of Greenhouse Gases for numerous industrial business segments, including refineries and offshore production, which became effective December 29, 2009. These were followed by a more recent regulation requiring Mandatory Reporting of Greenhouse Gases for Petroleum and Natural Gas Systems, including onshore exploration and production facilities, which became effective December 31, 2010 and was revised December 23, 2011. During 2011, U.S. federal legislation (EPA s Greenhouse Gas Endangerment Finding, EPA s Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Low Carbon Fuel Standards, etc.) and various state actions were proposed/finalized to develop statewide or regional programs, each of which have or could impose mandatory reductions and reporting of greenhouse gas emissions. Murphy believes it has met all of the EPA required reporting deadlines and strives to ensure accurate and consistent emissions data reporting. The impact of existing and pending climate change legislation, regulations, international treaties and accords could result in increased costs to the Company to (i) operate and maintain facilities; (ii) install new emission controls on facilities; and (iii) administer and manage any greenhouse gas emissions trading program. These actions could also impact the consumption of refined products, thereby affecting gasoline and ethanol marketing operations. The physical impacts of climate change present potential risks for severe weather (floods, hurricanes, tornadoes, etc.) at certain of the Company s refined product terminals in the U.S. and its offshore platforms in the Gulf of Mexico. Commensurate with this risk is the possibility of indirect financial and operational impacts to the Company from disruptions to the operations of major customers or suppliers caused by severe weather. The Company has repositioned itself to take advantage of potential climate change opportunities by acquiring renewable energy sources through the acquisition of two ethanol production facilities, thereby achieving a lower carbon footprint and an enhanced capability to meet governmental fuel standards. The Company is unable to predict at this time how much the cost of compliance with any future legislation or regulation of greenhouse gas emissions, or the cost impact of natural catastrophic events resulting from climate change, if it occurs, will be in future periods.

The Company recognizes the importance of environmental stewardship as a core component of its mission as a responsible international energy company and has implemented sufficient disclosure controls and procedures to capture and process environmental, safety and climate-change related information. As a companion to Murphy s EHS Policy, the Company s Web site also contains a statement on climate change. Not only does this statement on climate change include Murphy s goal of reducing greenhouse gas emissions on an absolute basis while growing its upstream and certain downstream operations, the information on the Company s Web site describes actions already taken to move towards that goal. These efforts include incorporating climate change into the Company s planning processes, reducing emissions, pursuing new opportunities and engaging legislative and regulatory entities externally. In support of these efforts, worldwide greenhouse gas inventories have been conducted since 2001. Additionally, Murphy participates in the Massachusetts Institute of Technology (MIT) Joint Program on the Science and Policy of Global Change. The initiatives cited above demonstrate the Company s commitment regarding environmental issues, which are at the forefront of today s global public policy dialogue.

Other Matters

The Energy Independence and Security Act (EISA) was signed into law in December 2007. The EISA, through EPA regulation, requires refiners and gasoline blenders to obtain renewable fuel volume or representative trading credits as a percentage of their finished product production. EISA greatly increases the renewable fuels obligation defined in the Renewable Fuels Standard (RFS) which began in September 2007. Murphy is actively blending renewable fuel volumes through its retail and wholesale operations and trading corresponding credits known as Renewable Identification Numbers (RINs) to meet most of its obligation. On July 1, 2010, the RFS-2 standard came into effect requiring the blending/phase-in of ethanol, biodiesel, cellulosic and advanced renewable fuels. Murphy is meeting its obligations for RFS-2 primarily through the RINs system.

The Company is also involved in personal injury and property damage claims, allegedly caused by exposure to or by the release or disposal of materials manufactured or used in its operations. Under Murphy s accounting policies, an environmental liability is recorded when such an obligation is probable 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. Recorded liabilities are reviewed routinely. Actual cash expenditures often occur one or more years after a liability is recognized.

Safety Matters

The Company is subject to the requirements of the Federal Occupational Safety and Health Act (OSHA) and comparable state statutes 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 OSHA requirements, including general industry standards, record-keeping requirements and 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 and petroleum product 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. Natural gas prices are 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. Prices for oil field goods and services have generally risen (with certain of these price increases such as drilling rig day rates having been significant at times) during the last few years primarily driven by high demand for such goods and services when oil and gas prices were strong. As noted earlier, oil and natural gas prices have been extremely volatile over the last several years. Oil prices were very strong in early to mid 2008, then fell precipitously in late 2008 and into early 2009, then have generally strengthened since that time. The prices for oil field goods and services

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generally rise in periods of higher oil prices and do not usually decline as significantly as oil and gas prices in a lower price environment. Should oil prices continue to rise in future periods, the Company anticipates that prices for certain oil field equipment and services could rise sharply. Due to the volatility of oil and natural gas prices, it is not possible to determine what effect these prices will have on the future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements The Company adopted guidance issued by the Financial Accounting Standards Board (FASB) regarding accounting for transfers of financial assets effective January 1, 2010. This guidance makes the concept of a qualifying special-purpose entity as defined previously no longer relevant for accounting purposes. Therefore, formerly qualifying special-purpose entities were reevaluated for consolidation by reporting entities in accordance with the applicable consolidation guidance. This adoption of this guidance did not have a significant effect on the Company s consolidated financial statements.

The Company adopted, effective January 1, 2010, guidance issued by the FASB that requires a company to perform an analysis to determine whether its variable interests give it a controlling financial interest in a variable interest entity. The primary beneficiary of a variable interest entity has both the power to direct the activities of the entity that most significantly impact the entity s economic performance and the obligation to absorb potentially significant losses of the entity or the right to receive potentially significant benefits from the entity. A company is required to make ongoing reassessments of whether it is the primary beneficiary of a variable interest entity. This guidance also amended previous guidance for determining whether an entity is considered a variable interest entity. The adoption of this guidance did not have a significant effect on the Company s consolidated financial statements.

In July 2010, the FASB issued accounting guidance that expanded the disclosure requirements about financing receivables and the related allowance for credit losses. This guidance became effective for the Company at December 31, 2010. Because the Company has no significant financing receivables that extend beyond one year, the impact of this guidance did not have a significant effect on its consolidated financial statement disclosures.

The U.S. Securities and Exchange Commission (SEC) adopted revisions to oil and natural gas reserves reporting requirements which were effective for the Company at year-end 2009. In January 2010, the FASB issued guidance that aligned its oil and gas reserves reporting requirements and effective date with the SEC s guidance. The primary changes to reserves reporting included:

- A revised definition of proved reserves, including the use of unweighted average oil and natural gas prices in effect at the beginning of each month during the year to compute such reserves,
- Expanding the definition of oil and gas producing activities to include non-traditional and unconventional resources, which includes the Company s Canadian synthetic oil operations at Syncrude,
- Allowing companies to voluntarily disclose probable and possible reserves in SEC filings,
- Amending required proved reserve disclosures to include separate amounts for synthetic oil and gas,
- Expanded disclosures of proved undeveloped reserves, including discussion of such proved undeveloped reserves five years old or more, and
- Disclosure of the qualifications of the chief technical person who oversees the Company s overall reserve process.

The Company utilized the new SEC and FASB guidance at December 31, 2011, 2010 and 2009 to determine its proved reserves and to develop associated disclosures. The Company chose not to provide voluntary disclosures of probable and possible reserves in this Form 10-K.

In September 2011, the FASB issued an accounting standards update that simplifies the annual goodwill impairment assessment process by permitting a company to assess whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount before applying the two-step goodwill impairment test.

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If a company concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the company would be required to conduct the current two-step goodwill impairment test. This change is effective for annual and interim goodwill impairment tests performed in fiscal years beginning in 2012. Early adoption is permitted. The Company does not expect the adoption of this standard in 2012 to have a significant effect on its consolidated financial statements.

In June 2011, the FASB issued an accounting standards update that only permits two options for presentation of Comprehensive Income. Comprehensive Income can be presented in (a) a single continuous Statement of Comprehensive Income, including total comprehensive income, the components of net income, and the components of other comprehensive income, or (b) in two separate but continuous statements for the Statement of Income and the Statement of Comprehensive Income. The new guidance is effective for the Company beginning in the first quarter of 2012. As in prior years, the Company expects to continue to present the Statements of Income and Comprehensive Income in two separate statements, and the adoption of this guidance in 2012 is not expected to have a significant effect on the Company s consolidated financial statements. In December 2011, the FASB deferred the requirement for reclassification adjustments from accumulated other comprehensive income to be measured and presented by line item in the Statements of Income and Comprehensive Income.

The United States Congress passed the Dodd-Frank Act in 2010. Among other requirements, the law requires companies in the oil and gas industry to disclose payments made to the U.S. Federal and all foreign governments. The SEC was directed to develop the reporting requirements in accordance with the law. The SEC has issued preliminary guidance and has received feedback thereon from interested parties. The preliminary rules indicated that payment disclosures would be required at a project level within the annual Form 10-K report beginning with the year ending December 31, 2012. The SEC has not issued final guidance regarding required disclosure. Therefore, it is expected that reporting will be delayed beyond year-end 2012. The Company cannot predict the final disclosure requirements that will be required by the SEC.

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.

Proved oil and gas reserves Proved oil and gas 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 regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic method or probabilistic method is used for the estimation. Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared 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 that we use an unweighted average of the oil and gas prices in effect at the beginning of each month of the year for determining proved reserve quantities. 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 reserve quantities. Reserve revisions inherently lead to adjustments of the Company s depreciation rates and the timing of settlement of asset retirement obligations. Downward reserve revisions can also lead to significant impairment expense. The Company cannot predict the type of oil and natural gas reserve revisions that will be required in future periods. The Company s proved reserves of oil and natural gas are presented on pages F-48 and F-49 of this Form 10-K.
Murphy has utilized reliable geologic and engineering technology in 2011 to include proved undeveloped reserves more than one location from producing wells in the more developed portions of the Eagle Ford Shale. The study incorporated public and proprietary data from multiple sources and encompassed the entire basin. This included analysis of seismic data, well log data, test production and fluids properties to establish geologic consistency as well as significant statistical performance data yielding predictable and repeatable reserve estimates within certain analogous areas. These locations were limited to only those areas with both established geologic consistency and sufficient statistical performance data where such data could be demonstrated to provide reasonable certain results.

Oil proved reserves revisions

Positive proved oil reserve revisions in the U.S. in 2011 were primarily associated with better production at the Medusa field in the Gulf of Mexico. Positive 2011 oil revisions for Canada conventional operations were mostly attributable to better well performance at the Hibernia field, offshore Eastern Canada. Synthetic oil operations had positive reserve revisions in 2011 due to change in royalty rate. Positive oil revisions in 2011 in Malaysia were primarily at the Kikeh field caused by production performance. Positive oil revisions in the U.K. in 2011 were associated with the Schiehallion field which is being redeveloped by its owners. The negative revision in oil reserves in Republic of the Congo in 2011 was attributable to poor production results for wells in the field. The positive revision in U.S. proved oil reserves in 2010 was primarily associated with better than anticipated performance of wells at the Thunder Hawk and Medusa fields in the Gulf of Mexico. Better well performance at the Hibernia and Terra Nova fields led to favorable proved oil reserve revisions in Canada in 2010. Proved oil reserves for Canadian synthetic oil operations had a positive revision in 2010 primarily due to a lower royalty. The positive proved oil reserve revision in Malaysia in 2010 primarily related to better well performance at the Kikeh field. A positive proved oil reserve revision in Republic of the Congo in 2010 was attributable to improved terms under the production sharing agreement that allocated a larger share of production at the Azurite field to the account of the Company beginning in October 2010. A favorable oil reserve revision in 2009 in the United States was attributable to favorable performance of the Thunder Hawk and Front Runner fields and federal royalty relief for various deepwater fields. A favorable conventional oil revision in Canada in 2009 was caused by performance of the Terra Nova field and improved heavy oil pricing which added reserves in the Seal area. Due to changes in the SEC s definition of proved oil reserves, which were first effective as of December 31, 2009, synthetic oil reserves are now included as proved oil reserves. Consequently, total synthetic oil reserves as of January 1, 2009 of 131.6 million barrels were added to total oil reserves in 2009. The positive revision to synthetic oil reserves during 2009 was attributable to lower royalties compared to a year earlier. An unfavorable revision to oil reserves in Malaysia in 2009 was due to current-year drilling results for a well in the Kikeh field, along with reduced entitlements at Kikeh and West Patricia due to increased prices in 2009 compared to year-end 2008. Oil reserves in the U.K. reflected an unfavorable revision in 2009 because of an anticipated reduction in life expectancy for major equipment at the Schiehallion project.

Natural gas proved reserves revisions

Proved natural gas reserves in the U.S. had negative revisions in 2011 due to well performance being less than expected in early wells drilled in the gas-prone regions of the Eagle Ford Shale in South Texas. Positive gas reserve revisions in Canada in 2011 were primarily at the Tupper and Tupper West areas and these were based on better than anticipated well performance. Negative gas reserve revisions in Malaysia in 2011 were primarily due to higher sales prices which effectively reduced the entitlement percentage for

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future production at the Sarawak gas fields. Negative gas reserve revisions in the U.K. in 2011 were essentially caused by revised estimate of gas-cap volumes at the Mungo/Monan field. Proved natural gas reserves in the U.S. had positive revisions in 2010 due to better well performance at the Thunder Hawk and Mondo fields in the Gulf of Mexico. The positive gas reserve revision in Canada in 2010 was attributable to performance at various wells in the Tupper area of British Columbia. Proved reserves of natural gas in Malaysia were revised downward in 2010 due to higher prices leading to a lower future entitlement percentage for the Company. Positive gas reserve revisions in the U.K. in 2010 were attributable to better well performance at all gas producing fields. In 2009, a positive U.S. gas reserve revision was caused by favorable performance of the Thunder Hawk, Front Runner and Mondo NW fields as well as federal royalty relief for various deepwater fields. In Malaysia, a combination of increased entitlements due to pricing and drilling performance at the Sarawak gas project led to positive gas revisions in 2009. Gas reserves in the U.K. were favorably revised in 2009 because of the Amethyst field gas compression project and better Mungo field performance.

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, all development capital expenditures and asset retirement costs 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 2011, a dry hole was recorded for a well drilled in Republic of the Congo in 2009. A significant reduction in proved oil reserves at the Azurite field in the same MPS block during 2011 reduced the likelihood of this well being produced in future years. In 2010, a dry hole was recorded for a well in the North Sea that was drilled in 2008. Extensive evaluations of this oil discovery determined in 2010 that recovery of hydrocarbons was not economical in the current price environment. There were no dry holes in 2009 that were drilled in prior years.

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, future margins on refined products produced and sold, and future inflation levels. The need to test a property 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 reserve revisions, expected deterioration of future refining and/or marketing margins for refined products, 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. In assessing potential impairment involving refining and marketing assets, the Company evaluates its properties when circumstances indicate that carrying value of an asset may not be recoverable from future cash flows. 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 margins, 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. Impairment expense of $368.6 million was recognized in 2011 to reduce the carrying value of the Azurite oil field, offshore Republic of the Congo, to fair value. The expense was necessitated by a significant year-end 2011 reduction of proved reserves at this field which was caused by poor well performance. Additionally, an impairment expense of $5.2 million was recorded in 2009 to write-off the remaining carrying value of one underperforming natural gas field in the Gulf of Mexico. Based on an evaluation of expected future cash flows from properties at year-end 2011, the Company does not believe it had 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 often reflect higher expected prices for oil and natural gas in the future compared to the existing spot prices at the time of assessment. If quoted prices for future years had been lower, the smaller projected cash flows for properties could have led to significant impairment charges being recorded for certain properties in 2011. In addition, one or a combination of factors such as lower future sales prices, lower future production, higher future costs, lower future margins on refining and marketing sales, 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 dismantlements and retirement benefit plan liabilities. 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 H and PM 311/312 in Malaysia and Blocks MPS and MPN in Republic of the Congo, for exploration licenses in certain areas, the largest of which are Australia, Suriname, 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. 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 accruals 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 of its full-time employees. 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 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 year-end 2011, the Company has used a discount rate of 4.87% at year-end 2011 and beyond for the primary U.S. plans. 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 pension expense from wide swings in liabilities and asset valuations. The Company s normal annual retirement and postretirement plan expenses are expected to increase slightly in 2012 compared to 2011 based on the effects of a growing employee base. In 2011, the Company paid $38.4 million into various retirement plans and $4.1 million into postretirement plans. In 2012, the Company is expecting to fund payments of approximately $35.5 million into various retirement plans and $5.8 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. 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 2012 annual retirement and postretirement expenses by $6.1 million and $0.9 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2012 retirement expense by $2.4 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 2012 under such contractual obligations and arrangements are shown below.

	Amount of Obligations				
(Millions of dollars)	Total	2012	2013-2014	2015-2016	After 2016
Total debt including current maturities	$ 599.6	350.0	0.1	0.1	249.4
Operating leases	826.3	161.6	265.2	150.2	249.3
Purchase obligations	2,513.4	1,967.4	478.7	47.4	19.9
Other long-term liabilities	1,277.3	98.6	120.7	229.5	828.5
Total	$ 5,216.6	2,577.6	864.7	427.2	1,347.1

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 the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide financial guarantees or letters of credit that may be drawn upon if the Company fails to perform under those contracts. The amounts of commitments as of December 31, 2011 that expire in future periods are shown below.

	Amount of Commitments				
(Millions of dollars)	Total	2012	2013-2014	2015-2016	After 2016
Financial guarantees	$ 7.8		3.2		